annual report

2004

CONNACHER OIL AND GAS LIMITED

strong finish
strong projects
strong future

2004 Highlights

- Debt free at year-end
- Company-maker project acquired at Great Divide
- International holdings reorganized into Petrolifera Petroleum Limited
- Significant Peruvian licenses negotiated by Petrolifera in early 2005

Corporate Profile

Connacher Oil and Gas Limited is a Calgary–based Canadian oil and natural gas exploration and production company. Its principal asset is a 100 percent interest in 101 sections (64,640 acres) of oil sands leases at its Great Divide oil sands project near Fort McMurray, Alberta. It also holds conventional assets at Battrum, Tompkins and Steelman, Saskatchewan.

Additionally, at year end, Connacher owned 61 percent of Petrolifera Petroleum Limited, which owns 100 percent of the productive Puesto Morales/Rinconada concession in the Neuqen Basin, Argentina. Petrolifera is also finalizing two licenses covering over five million acres onshore Peru.

In pursuing its objective of maximizing shareholder value, where possible Connacher secures large, operated interests. Over time, a balanced portfolio of oil and natural gas interests is being pursued. An opportunistic approach, supported by timely decisions, reflects management's experience and aggressive strategy towards realizing growth objectives.

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Annual and Special Meeting :
3:00 p.m. (MDT) Tuesday, May 10, 2005 Third Floor, Watermark Tower
530 – 8th Avenue SW Calgary, Alberta Canada T2P 3S8

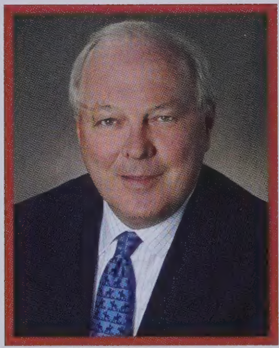
Operating & Financial Highlights

	Years ended December 31		
	2004	2003	% Change
Financial ($)		(restated)	
Total revenue	**11,215,888**	9,982,291	12
Cash flow from operations (1)	**2,409,365**	3,352,778	(28)
Per share, basic (1)	**0.05**	0.10	(50)
Per share, diluted (1)	**0.05**	0.10	(50)
Net earnings (loss)	**(2,976,411)**	4,054,778	-
Per share, basic	**(0.06)**	0.13	-
Per share, diluted	**(0.06)**	0.12	-
Capital expenditures	**17,628,534**	35,789,621	(51)
Dispositions	**17,604,310**	-	-
Shareholders' equity	**40,501,988**	24,182,085	67
Total assets	**46,217,113**	53,776,977	(14)
Operations			
Daily Production			
Oil and liquids (bbl/d)	**785**	789	(1)
Natural gas (mcf/d)	**1,620**	1,190	36
Equivalent (boe/d) (2)	**1,055**	987	7
Proven, Probable and Possible Reserves (3)			
Oil and liquids (mbbls)	**56,210**	5,465	929
Natural gas (mmcf)	**4,212**	9,557	(56)
Combined (mboe) (2)	**56,912**	7,058	706
Selling price ($/boe)	**28.95**	27.56	5
Operating cost ($/boe)	**9.38**	8.15	15
Shares Outstanding (000)			
Weighted average			
basic	**50,907,942**	32,362,110	57
diluted	**53,328,551**	35,333,124	51
End of period			
issued	**89,626,743**	45,902,925	95
fully diluted	**98,915,868**	53,717,070	84

(1) Cash flow from operations and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by others.

(2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) 2004 and 2003 reserves compiled based on National Instrument 51-101 (NI 51-101).



R.A.Gusella
President & Chief Executive Officer

Letter to Shareholders

2004: A CHALLENGING AND REWARDING YEAR

Connacher experienced mixed results during 2004. The year started with great promise – new natural gas production coming onstream; the low-cost purchase of 83 sections (53,120 acres) of oil sands leases at our Great Divide project near Fort McMurray, Alberta and a new high for the share price. The company appeared to have momentum and to have successfully applied its strategy to enhance shareholder value.

Unfortunately this promise was short-lived, as by March 2004 we had experienced disappointing production results at Cabri, Saskatchewan. This translated into weaker than expected cash flow and rising levels of net debt. As would be expected, this also triggered a steep deterioration of our share price.

In the face of these unfortunate events, we did not capitulate. Instead, we adopted a plan to transform, redirect and strengthen your company. The plan incorporated asset sales, raising new equity and reorganizing our Argentinean holdings. I am pleased to report all of these elements were successfully completed by year end. As a result, Connacher had a strong finish to 2004. Now, with a company-maker project at Great Divide, a strengthened debt-free balance sheet, a self-financed international subsidiary in Petrolifera Petroleum Limited, a strengthened management team and a positive long-term outlook for the oil and gas industry, our future is again positive and strong.

GREAT DIVIDE

The biggest achievement of 2004 was the purchase of 101 sections (64,640 acres) of oil sands leases at our Great Divide project in Alberta's oil sands southwest of Fort McMurray.

We acquired most of these lands at a Crown sale in early 2004, having posted the acreage for sale in the latter part of 2003. Our management group had identified this opportunity based on their extensive career involvement in exploitation of heavy oil and oil sands. These rights were purchased at low cost because at the time the area was "off the radar screen." The lands acquired had some well control and indicators of McMurray channels. We were fortunate in being able to drill 11 new core holes on one of these channels (Pod One) before 2004 spring breakup, which confirmed the presence of a significant oil accumulation. Independent reserve evaluations confirmed our initial assessment.

During the balance of 2004, we did not have the financial wherewithal to acquire more lands. However, with the dramatic increase in oil prices during the year to more than US$50 per barrel for WTI, industry attention and investor interest in the oil sands accelerated. In mid-October 2004, lands adjacent to our Great Divide holdings sold for more than $1,200 per acre. By the December sale, the top price had surpassed $2,300 per acre. Clearly our quiet and early initiative paid off as our acquisition price was approximately $20 per acre.

Based on the information we now have about Pod One and the other leads or prospects already identified on our acreage, Great Divide is expected to be a company-maker project. As we complete our first quarter 2005 corehole program, plans are advancing to apply to the appropriate Alberta authorities to develop and commence a 10,000 barrel per day steam assisted gravity drainage ("SAGD") production project.

We are continuously evaluating alternative approaches to financing this and subsequent development projects at Great Divide. Our preference is to proceed with the project on a stand alone basis, if capital markets recognize the underlying value of the assets and thereby facilitate raising the required equity capital at reasonable levels with minimum dilution. Alternatively, we may seek an industry or financial partner, which would dilute our interest in the project, but substantially mitigate financial market risk. Your board is mindful of the importance of this decision and will undoubtedly focus much of its 2005 deliberations on this challenge.

OTHER ACTIVITIES

As a result of first quarter 2004 disappointments at Cabri and their compounding effects, Connacher curtailed its capital spending program after spring breakup. Our focus was on debt reduction and balance sheet restoration. We were able to sell our heavy oil properties at Lloydminster and Islay, Alberta for attractive prices before price differentials widened to the historically high levels reached in early 2005. Cabri natural gas reserves, wells, facilities and shallow rights were also sold for an attractive consideration. Connacher retained the deep rights for future exploration potential. While these sales reduced conventional activities in western Canada, they were necessary at the time and played a big role in our balance sheet reconstruction. Later in the year we raised over $21 million of new equity at reasonable prices, having recovered from the low levels of the third quarter, thanks to market recognition of the value of our oil sands holdings. This resurgence and recognition led to a successful share issue and proceeds received enabled Connacher to eliminate net debt by December 2004. While some of our trades and suppliers experienced payment delays during the year, they were all paid in full by year end. We appreciate the patience and cooperation shown by most service companies in 2004. Our relationships have been restored to normal conditions.

In addition to eliminating our bank debt in 2004, we now have cash in the bank, an unused credit facility of $8.6 million and the continued support and cooperation of our principal lender.

Finally, in late 2004 we successfully reorganized our international assets into a separately financed company, Petrolifera Petroleum Limited. This was accomplished by first buying the 50 percent interest in our Argentinean concession that Connacher did not already own, and then selling the entire interest to Petrolifera for shares and a promissory note. At December 31, 2004 Connacher retained a 61 percent equity stake as Petrolifera had concurrently raised funds from a private placement of treasury common shares. Subsequent to year end, Petrolifera negotiated two significant licences covering over five million acres onshore Peru. Petrolifera also raised $7 million of new equity in March 2005. Proceeds were used to repay $2 million of debt owed to Connacher. The balance, with cash flow from Argentinean production, will be used to finance an expected $6.2 million 2005 capital budget, which includes a 3D seismic program and a five-well drilling program on the Argentinean acreage. Work is also expected to commence on the Peruvian licenses in the Maranon and Ucayali Basins in Peru. If market conditions are accommodating, Petrolifera plans to go public later in 2005. Connacher will retain a significant equity stake in Petrolifera and continues to provide management services pursuant to a contractual relationship. Petrolifera has a strong debt-free balance sheet and an exciting balanced portfolio of opportunities.

OUTLOOK

Connacher has overcome several short-term challenges and has restored a strong outlook. World events, including rising demand for oil in China, India and other developing nations have led to a stronger price outlook for oil. Meanwhile, a strong future for other energy inputs, including natural gas, is also to be expected throughout the world. Strong industry fundamentals have facilitated competition for new world class opportunities such as the oil sands in Canada and new high-potential exploration blocks such as those secured by Petrolifera in Peru.

We are well situated to benefit from these circumstances. As the world consumes about 30 billion barrels of oil each year and with demand growing at unforeseen rates, our assets will appreciate in value, providing our shareholders with leveraged participation in Alberta's oil sands. Strong industry fundamentals along with our exposure to our Great Divide oil sands project should also attract expanded investor interest and support, which will assist in financing our project. The stable political situation in Canada, combined with proximity to the largest energy-consuming market in the world, should bring Connacher's growth potential into sharp focus in 2005 and beyond.

Petrolifera's initial success in gaining control of over five million acres of well-situated and highly prospective license rights in Peru, proximate to or on trend with known large oil and natural gas fields, bodes well for that company's future. South America may become of greater interest to the energy industry and capital markets in upcoming years due to the geopolitical and economic conditions faced by North American interests elsewhere in the world.

In closing, we regret the difficult periods experienced in 2004. We believed our shallow gas initiative at Cabri was going to provide solid operating and financial results for many years. This did not prove to be the case. Nevertheless, despite suffering share dilution, we weathered the storm, sorted out our problems and repositioned Connacher with a strong project at Great Divide and a strong outlook for 2005. This is reinforced by a strong balance sheet, strengthened management group and focused new opportunities. Our current market capitalization exceeds $100 million, more than 50 percent above its peak in early 2004. The best is yet to come!

During 2004, we promoted Mr. Peter Sametz to the position of Executive Vice President and Chief Operating Officer. Mr. Tim O'Rourke was appointed to Vice President, Oil Sands Operations and Mr. Richard Kines was appointed Vice President, Finance in addition to his role as Chief Financial Officer. We thank these experienced and well-qualified individuals and all of our staff for their diligence, loyalty and hard work during a challenging year. We look forward to their contribution to Connacher's future success. In March 2005 Mr. Gary D. Wine was appointed to the position of President of Petrolifera. Mr. Wine is a seasoned explorationist and is a recognized expert in Peruvian geology. He played a significant and instrumental role in Petrolifera's success in negotiating the two new licenses in Peru and also has considerable experience in Argentina.

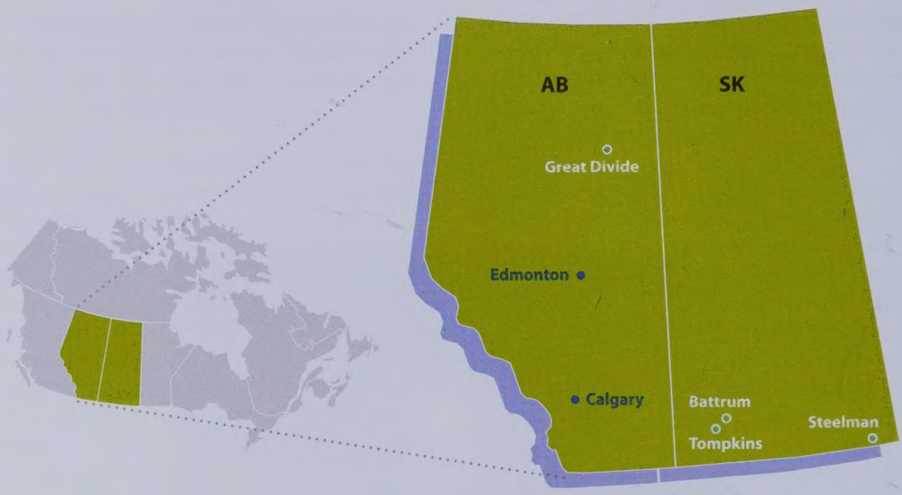
We thank Mr. Colin Evans, who joined the board at a difficult time in the company's development in 2004 and who, along with our other board members, contributed long hours and sound advice as Connacher repositioned itself for success. We are also pleased to advise that Mr. Stewart McGregor has been selected our Lead Director and Mr. Evans has become Chairman of the Audit Committee.

We thank our shareholders for their enduring support, especially during a challenging year. It is our hope 2005 will yield robust results that flow from Connacher's strong finish to 2004.

Respectfully submitted on behalf
of the Board of Directors

Signed,
"R.A Gusella"
Richard A. Gusella
President and Chief Executive Officer

March 23, 2005



Review of Operations

OVERVIEW

Peter D. Sametz
Executive Vice President and Chief Operating Officer

Connacher transformed itself and its operating strategy in 2004. In part, this was motivated by the disappointing results of an uncoventional gas play at Cabri, Saskatchewan. Connacher needed to respond, and Connacher met the challenge. Our strong finish established a sound basis for sustainable growth.

On a more positive note, there was the acquisition of a significant asset base at Great Divide, Alberta, where an initial 83 sections (53,120 acres) and eventually 101 sections (64,640 acres) of 100 percent-owned oil sands leases were acquired during the year. The prospective value of Great Divide could be considerable.

During the year the company crystallized its focus, streamlined its operations, was able to raise new capital and sold less desirable properties to eliminate net debt and can now concentrate more effectively on its major asset. Connacher's remaining conventional Canadian assets at Battrum, Tompkins and Steelman, all in Saskatchewan, will continue to provide a solid revenue and cash flow base, with attendant credit capacity for financial flexibility. These properties will be subjected to continuous infill and follow-up drilling and engineering initiatives to maintain and grow productivity. However, when compared to the Great Divide oil sands project, they are minor in their relative importance to Connacher's future.

Consistent with its emphasis on focus and to streamline its affairs, Connacher also successfully enhanced the value of its Argentinean assets by first acquiring its joint venturer's 50 percent interest in the prospective and productive Puesto Morales/Rinconada concession in the Neuquen Basin, and then securitizing this interest. This was done by selling the combined 100 percent interest to a subsidiary, Petrolifera Petroleum Limited, for eight million Petrolifera common shares and a $4 million note. Concurrently, Petrolifera raised new equity funds from various private investors and repaid $1.25 million to Connacher, reducing the note to $2.75 million. Accordingly, at year end Connacher retained 61 percent of Petrolifera, had recovered as much cash as probably could have been secured from a direct sale of its 50 percent non-operated interest and was in line to receive more cash, having positioned itself to participate in Petrolifera's growth through its equity stake. Petrolifera's accounts were consolidated with Connacher's at year-end.

In early 2005, Connacher supported Petrolifera in its quest for two significant licenses onshore the Maranon and Ucayali Basins, Peru. The related Blocks 106 and 107, respectively, comprise two million and three million acres. The Maranon Block 106 is offset by numerous oil fields, surrounds the largest oil field in the basin and is bisected by an underutilized crude oil pipeline. Work commitments are reasonable and license terms are considered most favorable by international standards.

The Ucayali Block 107 is more exploratory in nature but importantly is on trend with and exhibits geological characteristics similar to the giant Camisea Complex to the southwest, where reserves are reported by Perupetro, the Peruvian government agency, at 16.4 Tcf and 850 million barrels of condensate and natural gas liquids. Other smaller fields offset this massive block.

In exchange for its assistance to Petrolifera, Connacher received a minor share option and a 10 percent carried working interest in each license through the drilling and completion or abandonment of the first well on each block. The carried interest is convertible, at Connacher's election, into a gross overriding interest of two percent.

Petrolifera completed a $7 million equity financing at $1.00 per unit (comprised of one share, one half share purchase warrant and a right) in March 2005, repaying a further $2 million to Connacher from part of the proceeds. This has reduced Connacher's stake in the company to 40 percent. Petrolifera is now self-sufficient and if market conditions are accomodating the company intends to raise more capital and go public in 2005. Connacher's stake has already seen a considerable value enhancement.

SUMMARY 2004 REVIEW

Production during 2004 averaged 1,055 boe/d comprised of 785 bbl/d of crude oil and 1,620 mcf/d of natural gas. Canadian production accounted for 93 percent of crude oil volumes and 55 percent of natural gas sales. Production levels were affected by the mid-year disposition of approximately 500 to 550 boe/d of production from Lloydminster/Islay, Alberta and Cabri, Saskatchewan.

Peak production occurred in June 2004 at 1,434 boe/d with peak crude oil sales at 1,112 bbl/d during the second quarter. Volumes had risen 58 percent and 42 percent, respectively, during the first and second quarters before the decision to sell certain underperforming or high-cost properties to reduce net debt. Despite these sales, overall volumes still rose seven percent during 2004.

Capital expenditures during the year totaled $17.6 million before proceeds from dispositions, which were also $17.6 million. Outlays largely occurred during the first quarter of 2004, followed by a quieter period as attention was focused on sales and debt reduction. Major expenditures during 2004 were made at Great Divide, Alberta for land and 11 core holes; at Cabri, Saskatchewan for drilling, facilities and workovers prior to selling the property; at Tompkins, Saskatchewan for drilling and at Battrum, Saskatchewan where production increased during 2004. A total of 14 conventional wells and 11 Great Divide core holes were drilled during the year. All conventional wells were cased and all activity was at 100 percent working interest.

At December 31, 2004, Connacher's proved, probable and possible reserves as estimated by DeGolyer and MacNaughton Canada Limited ("D&M") were 56.9 million boe. Using forecast prices, the estimated 10 percent present worth of pre-tax future net revenue was $33.2 million for proved and probable reserves and $175 million for proved, probable and possible reserves. These volume estimates and the forecast present worth of future net revenue were calculated net of 2004 dispositions and in compliance with NI 51-101 parameters. Possible reserves are largely associated with Great Divide. Volume estimates have not been updated to reflect drilling of new core holes in early 2005 as this is not permitted under NI 51-101. Connacher expects

both values and volumes will increase once new data is incorporated and price decks stabilize.

Conventional operating and transportation costs rose by \$1.28 per boe during 2004 to \$9.75 per boe, reflecting the maturity of certain fields and startup issues at Cabri, Saskatchewan (since sold). These costs declined sharply since the mid-year sale of production and reserves and averaged \$8.34 per boe during this later period, declining to \$5.64 per boe in December 2004. This augers well for increased efficiency in 2005. While selling prices were modestly higher in 2004 at \$28.95 per boe compared to \$27.56 in 2003, 11 percent higher royalties and the higher operating costs resulted in netbacks declining by a modest four percent to \$13.75 per boe. A higher Canadian dollar and expanding differentials with resultant hedging losses affected average prices adversely during a year when WTI rose 33 percent to average US \$41.44 during the year.

Connacher's inventory of undeveloped Canadian acreage more than doubled during 2004 to 54,380 net hectares (135,950 net acres). The company's working interest averages 92 percent and all properties are operated. Major acreage increases occurred at Great Divide, Alberta and at Tompkins, Saskatchewan. An independent evaluator assessed Connacher's domestic acreage pursuant to NI 51-101 parameters at \$6.8 million.

The company's year-end acreage inventory also increased in Argentina through the purchase of a joint venturer's 50 percent interest in the 95,000-acre Puesto Morales/ Rinconada Concession. Undeveloped foreign properties were not evaluated for year-end reporting purposes.

GREAT DIVIDE, ALBERTA

General

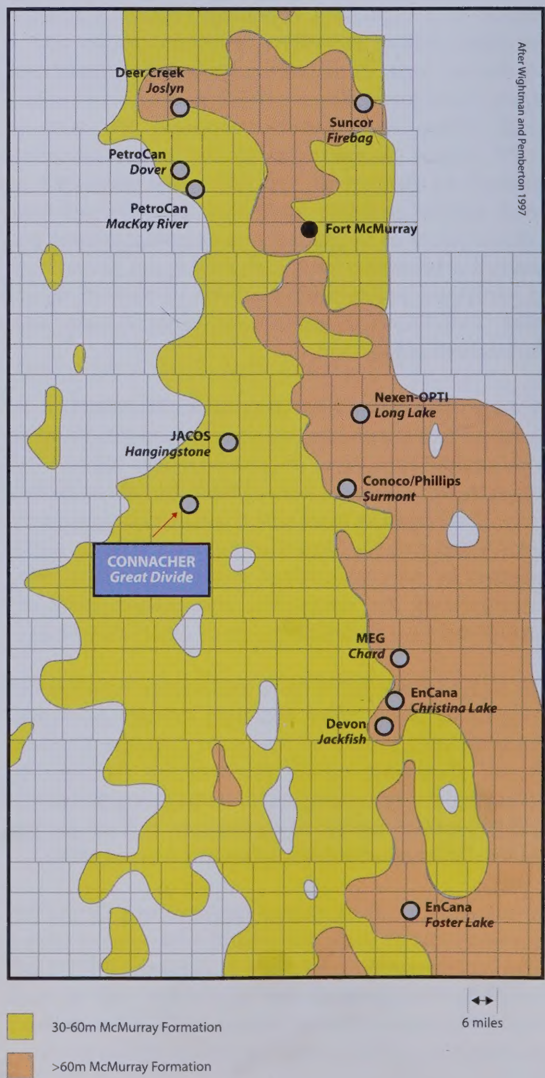

Timothy J. O'Rourke
Vice President,
Oil Sands Operations

In late 2003, Connacher took a bold initiative by posting and then subsequently acquiring 83 sections (53,120 acres) of oil sands leases at the January 7, 2004 Alberta Crown Sale. Additionally in December 2004 a further 18 sections (11,520 acres) were acquired, bringing the company's total land position to 101 sections (64,640 acres) in the Divide region of northeast Alberta. These lands and related reserves ("Great Divide") have become Connacher's single most important asset. They have **company-maker** potential. This initiative was consistent with Connacher's overall goal of maximizing shareholder value and its underlying strategy of being opportunistic, capitalizing on in-house expertise and securing exposure to company-maker opportunities. Great Divide is a strong project which, when onstream, will contribute to a quantum leap in production, cash flow and the value of the company.

Why Connacher is in the Oil Sands

Prior to acquiring its Great Divide acreage, Connacher's management and technical experts had evaluated the available lands and wells in the region. This study and analysis concluded that there was a strong potential for the existence of several McMurray channels ("Pods") which, while not overly large in areal extent, could contain significant and sufficient in-place oil reserves to support steam assisted gravity drainage ("SAGD") production projects in the 10,000 bbl/d range. These Pods were expected to be two to four sections (1,280-2,560 acres) in size. With sufficiently thick net SAGD pay in the McMurray channels and given the expected quality and richness of the reservoir, with oil-in-place expected to exceed 2,000 barrels per acre-foot of reservoir, a Pod this size with 50 feet or more of net SAGD pay could contain 100 to 300 million barrels of bitumen. With SAGD recovery factors estimated at up to 60 percent, it

Regional Map - SAGD Projects



was apparent a lot of oil could be recovered over time if prices were reasonable, capital and operating costs were controllable, price differentials for lower quality bitumen were normal and first phase financing could be secured. Connacher expects over 80 percent of the oil which will ultimately be produced from the region will be recovered using SAGD technology.

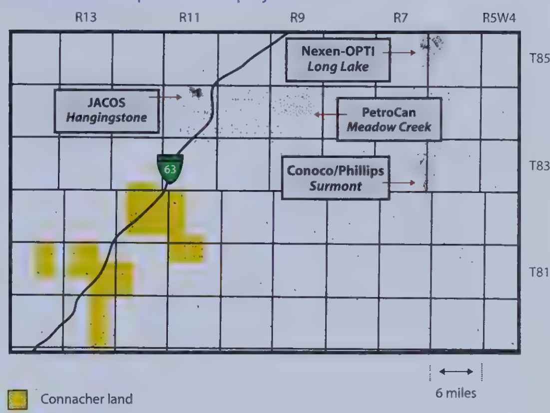
Once Connacher's management identified the Great Divide oil sands opportunity, decisions were made in late 2003 to post and then to acquire acreage to cover a number of McMurray Channel leads which had been identified during the technical review of the area. These lands were located in a region affected by the "gas over bitumen" controversy and thus were somewhat "off the radar screen." Lands were also posted for an early-year 2004 sale to capitalize on possible industry inattention.

Connacher's move into the oil sands was recognition of the solid long-term company-maker potential of the region and play. It was one area where a smaller, opportunistic company like Connacher could participate in 'big oil' in a mature basin such as Western Canada. Also, since the late 1980's, the company's management possessed extensive experience and expertise in the oil sands, heavy oil and horizontal technology (including SAGD). Therefore, management felt confident in the initiative. There was also considerable appeal to the possibility of identifying and owning long-life reserves exceeding 25 years, as well as the prospect of several channels being identified on Connacher's lands. This would allow for **repeatability** and **sustainability** of growth profiles. With other larger operators already successfully applying SAGD technology in the region, Connacher's enthusiasm for Great Divide escalated throughout the year, buoyed by strong and rising worldwide demand for energy, resulting in higher oil prices.

The Great Divide Neighbourhood
{ Location, Location, Location }

Connacher's Great Divide project is primarily located in Townships 81 and 82, Ranges 11 to 13, W4M in northeastern Alberta. The company's lands are about 80 kilometres southwest of Fort McMurray, Alberta and in the same region as the Nexen-OPTI and Conoco/Phillips SAGD projects and south of the JACOS Hangingstone SAGD project, which is Connacher's closest analogue. Current production at Hangingstone is reported at approximately 9,000 bbl/d of bitumen with per well rates exceeding 1,000 bbl/d and some having reached as high as 1,500 bbl/d, based on publicly-available data.

Detailed well map with other projects



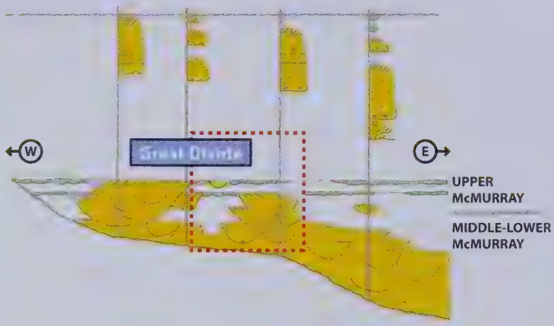
Connacher's acreage contains several identified channels or leads. The lands are bisected by Highway 63, the main highway running from Edmonton, Alberta to Fort McMurray. This is important for access and cost control as road construction in the region is expensive. Proximity to this highway already allowed Connacher to accelerate its evaluation program by accessing rigs returning south at the end of the drilling season in March 2004. This allowed the company to drill 11 core holes on its Pod One accumulation, confirming the presence of a significant and apparently exploitable accumulation and thus likely compressing the timeframe to first production by at least one year. Other infrastructure bisecting the Great Divide acreage block includes major oil and natural gas pipelines and power transmission lines. Their presence is expected to assist in accessing needed services and supplies.

Connacher's Great Divide project is in the Divide region of Alberta, so called because it is on relatively high ground in the area, which is also the reason the main highway was situated where it is. The region was subject to a major forest fire and burn several years ago, thereby making it less prone to environmental sensitivity than would otherwise be the case. There is no human habitation in the vicinity. Despite this, Connacher has already initiated important and required baseline environmental studies to support its planned application to regulatory authorities in the third quarter of 2005.

Subsurface, Connacher's acreage also appears to be well-situated. While indicated gross and net Middle McMurray pay is not necessarily as thick as some other projects of which the company is aware, Connacher's net SAGD pay is high quality. The associated in-place and recoverable reserves are expected to be more than adequate to support a commercially-attractive 10,000 bbl/d project for 25 years. As evidenced by the enclosed diagram of the facies at Great Divide, the company's project appears geologically well-situated with no bottom water and a benign and relatively flat Devonian

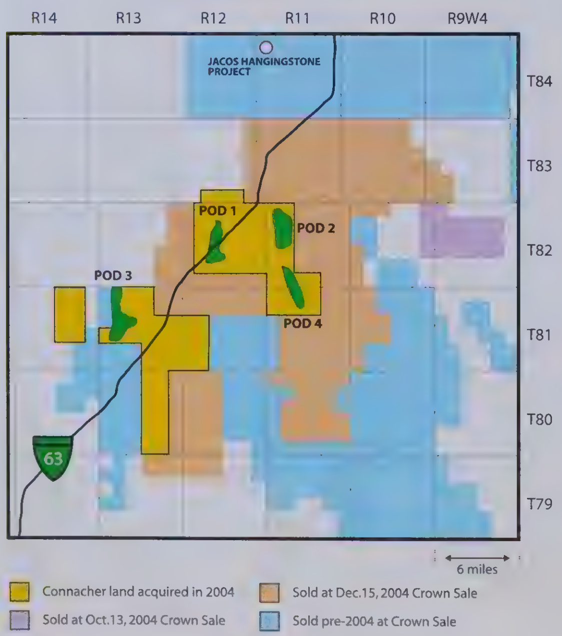
surface on which oil-bearing McMurray is deposited. This has resulted in a high ratio of net SAGD pay to gross pay. Furthermore, Connacher's bitumen content by weight appears to be relatively high, exceeding 12 percent and reaching up to 16 percent, which is 50 to 100 percent above normal cutoffs for this parameter in many mining ventures in the oil sands.

Great Divide Facies



During 2004, industry interest in Connacher's area of operation accelerated. Over $50 million was spent on land in the region. Bonuses reached as high as $2,360 per acre, over one hundred times Connacher's cost. These high prices were a reflection of the opportunity, the economics afforded by high oil prices, the proven available technology and recognition of the prospective profitability of smaller modular projects with "efficiencies of scale" as opposed to the general diseconomies which have come to characterize many large-scale oil sands projects. Connacher believes modular, smaller scale SAGD projects will become the order of the day, and that Connacher is as well-positioned as any other company at this juncture to develop its project. Furthermore, there is virtually no remaining geologically-attractive acreage available in the area.

Great Divide Land Holdings



The Great Divide Concept

Connacher's approach was to consider developing a number of smaller scale, efficient SAGD projects to exploit these sweet spots or Pods. This approach allows for lower capital investment up to first production. Initial expectations are capital expenditures of about $18,000 per barrel-day of production, an acceptable level by industry standards, even for conventional oil. As a smaller company, Connacher's focus was and is always on compressing the timeframe to first cash flow, which is the company's engine for growth. As a smaller scale project with a smaller footprint, there should be a less time-consuming regulatory review process, which also serves the company's cash flow objective. Finally, Connacher's anticipated modular approach at 'oil field' standards as opposed to 'refinery' standards should help control costs, reduce delays and facilitate the company's 'efficiencies of scale' objective.

Over time, Connacher is also interested in **repeatability** and **sustainability** while capitalizing on and incorporating technological change and progress for these types of projects, which is accelerating. Fortunately, it appears the company's lands could contain up to four or more exploitable leads, channels or Pods, each of which could prove to be of sufficient size and quality to support the sequential development of additional 10,000 bbl/d projects over the next three to five years. Of consequence is that when and if the first channel or Pod One is financed and developed, with high oil prices and stable production at minimal decline over a long-life, these projects generate substantial cash flow and possess considerable debt capacity. This minimizes the prospect of continuing equity dilution to finance future growth. As time passes, knowledge from the first Pod can hopefully be used to advantage in developing future Pods, thereby enhancing project economics. This could include progress in such areas as water handling, steam/oil ratios, pumping equipment and technology, alternative fuel sources and product upgrading.

Accessing infrastructure at low cost is also a big component of the economic equation for a successful exploitation project in the oil sands. For Connacher, the service sector and qualified people are nearby and accessible, saving time and money.

The project is being designed to capitalize on the company's upstream expertise. Initial production of 8° API bitumen could be subject to short-term price fluctuations due to quality differentials for heavier crudes which prevail in the marketplace from time to time. On occasion, Connacher may also have exposure to natural gas price volatility as natural gas will be

used for fuel to create the steam for SAGD. However, the indicated quality of reservoir at Great Divide could mitigate projected steam/oil ratios (forecast 2.5 to 3.0 times) and keep Connacher's costs at very acceptable levels until a decision is made about switching to direct burning of bitumen as a fuel source. Connacher is also fortunate in that it appears to have a substantial water source in an uphole formation, which will enable steam to be generated without use of surface water, which is a contentious modern issue.

Over time, Connacher expects some form of alignment with a downstream partner to hedge its exposure to volatile price differentials. Such a party could also potentially participate in the upstream project and be a significant source of development capital to minimize financial market risk and equity dilution to finance the project's first phase. This alternative or other joint venture arrangements will be evaluated by management and the board of directors during 2005 with a view to optimizing shareholder returns.

How the Project Will Work
{ Preliminary Appraisal }

Pod One and the other leads on Connacher's acreage were originally encountered by conventional wells which were previously drilled for natural gas. They were drilled to depths below the natural-gas-bearing zones or to basement, penetrating the oil-bearing McMurray in the process. This provided the initial indication of a valuable resource.

In early 2004, Connacher drilled 11 core holes on and around what the company calls Pod One to more clearly define the oil-bearing channel or Pod. The 11 core holes provided us with valuable reservoir information and a sense of the channel's geometry. Based on this early data, independent consultants D&M estimated Pod One possible recoverable reserves, determined in accordance with NI 51-101, of 52.3 million barrels. At year-end the D & M estimate of the 10 percent pre-tax present worth of Pod One reserves, using constant prices, was estimated to be \$211 million, after appropriate deductions for capital, royalties and operating costs. It is apparent Connacher's Great Divide project has considerable value to the company and its shareholders.

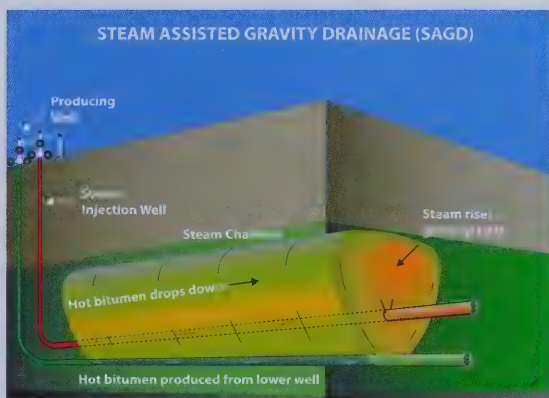
Additional drilling during the first quarter of 2005 has reaffirmed enthusiasm for the project. Updated resource studies will incorporate new data beyond that which could be recognized at year end 2004.

SAGD Technology

SAGD essentially consists of a series of horizontal well pairs, one drilled approximately five metres above the other. Generally, wells are drilled in clusters from a single pad and are spaced 100 metres apart to optimize recovery.

In SAGD, the upper well of the pair is used for the injection of steam into the reservoir, while the lower well bore is used for the collection and production of hot bitumen and hot water or condensed steam. With a relatively uncomplicated reservoir and basement, no bottom water and with the reservoir depth between 450 and 475 metres subsurface, Connacher should not require specially-built rigs, but can use conventional horizontal drilling technology to drill its wells.

The steam will be made by producing uphole formation water and heating it in boilers on the surface, initially with natural gas. The boilers and other surface facilities are expected to require over two thirds of the capital costs to be incurred prior to production. The balance will be for the subsurface, including drilling wells.



The concept of SAGD with horizontal well pairs is better overall distribution of the steam, higher eventual well productivity and eventually improved recovery factors. As the steam is injected into the upper wellbore, located about five metres above the producer, it rises and gives up its heat to the colder bitumen. This mobilizes the molasses-like oil such that it will flow and drop under the influence of gravity to the lower wellbore. In more modern application of SAGD, 'steam chambers', or the hot areas under the influence of steam from which the oil is drained, are expected to be operated at lower pressures.

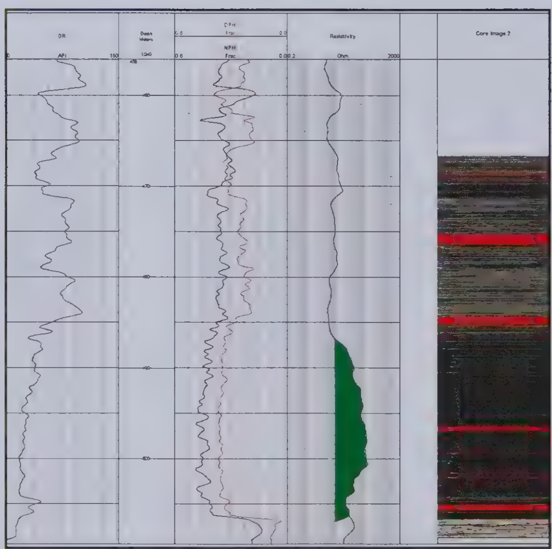
With lower steam pressures increasingly being utilized, the oil is generally pumped to surface. Pumping technology to handle hot oil has also advanced in recent years. The produced oil is separated from the hot water, stored and cooled down in surface batteries, treated and

blended with condensate or synthetic light oil and then would be delivered into the pipeline for sale to available markets.

Of consequence to the economics of this process are well productivity, the steam - oil ratio, fuel costs, eventual recovery factors (expected at 60 percent, ranging up to 80 percent), water source and quality, environmental impact (a small footprint for this scale of operation), crude oil prices, differentials, richness (bitumen by weight) of the reservoir, and reservoir quality. **Good reservoir is everything** and based on early numerical simulation studies, the company also expects good well productivity.

Importantly, Connacher also has an attractive actual analogue to Great Divide Pod One at the JACOS Hangingstone development situated approximately 15 kilometres to the north. Public data indicates recent wells are producing consistently with peak production exceeding 1,500 bbl/d and recoveries of as much as 1.5 million barrels from one well pair with minimal decline in just five years. Furthermore, recently-completed wells have shown a more rapid rise to target productivity than earlier wells. Connacher believes the reservoir at Pod One exhibits characteristics as good as or better than those at the Hangingstone project, which is positive for Great Divide.

Pod One Core Log



In the first quarter of 2005, twelve core holes were drilled in Pod One and seven core holes were drilled in Pod Three. What remains to be completed is a 3D seismic program over Pod One and then the integration of this data with the results of the nineteen core holes and other well data associated with Pod One. Preliminary indications are very positive.

Once the geometry and areal extent of Pod One is finally established, based on well control and 3D seismic, a resource study will be commissioned. The results will provide the company with an independent estimate of its oil-in-place and eventual recoverable reserves. This will be combined with simulation analysis, detailed engineering design of project facilities and environmental baseline studies in a submission to the Energy Utilities Board and Alberta Environment for a 10,000 bbl/d project. Their review and the receipt of approval could take until early 2006; this is a process which Connacher cannot control. Upon approval, project construction would be initiated, targeting a startup of steaming and then production.

Pod One Drilling Outline and Net SAGD Pay

The 10,000 bbl/d plant with steam will be designed to be operated at close to rated capacity over the life of the project. Actual per well pair productivity will determine the number of pads required over time to sequentially drain each channel. A forecast commercial life of 25 or more years per Pod is contemplated.

What Lies Ahead?

The company believes Great Divide has the potential to be a **company-maker project**.

A review of Great Divide's essential characteristics is in order. Connacher has a low cost extensive land base of 101 sections or 64,640 acres, in which it holds a 100 percent working interest. As operator, the company controls its own destiny in terms of scheduling and pace of development, subject to regulatory approvals.

Our lands are well-situated with good access and appear to be well-positioned geologically. The reservoir encountered thus far appears to be excellent, based on analysis to date of both cores and logs. Considerable reserves appear to have been identified.

Our approach is to develop modular smaller scale SAGD projects which, based on analysis to date of reserves, expected productivity capital and operating costs suggests the potential for considerable value addition, cash flow growth and future profitability.

The data indicates Connacher's lands could contain several accumulations or Pods. If confirmed by further drilling and evaluation, Connacher will have the prospect of **repeatability** and **sustainability**, important criteria for capital markets at a time when the company will need to raise new funds for Great Divide.

Connacher's management team has extensive experience with SAGD projects involving steam and horizontal technology.

Connacher is one of the few smaller public companies engaged in oil sands SAGD projects. It is anticipated that investor interest in the company will remain at a high level, as our company offers investors highly-leveraged exposure to oil sands value creation as Great Divide proceeds.

It should be noted, however, that these projects are not without risk. While Connacher's management and Board will do everything possible to optimize value, there are considerable capital requirements to first production. Accordingly, there is recognizable capital market risk if Connacher decides to develop Great Divide on its own. Offsetting this is the apparent availability of large sums of long-term capital for sound oil sands projects in a tight supply, high oil price environment such as is being experienced presently.

Our approach will also consider partnering as an alternative to proceeding alone. Which way is selected will be assessed carefully in the interest of our shareholders.

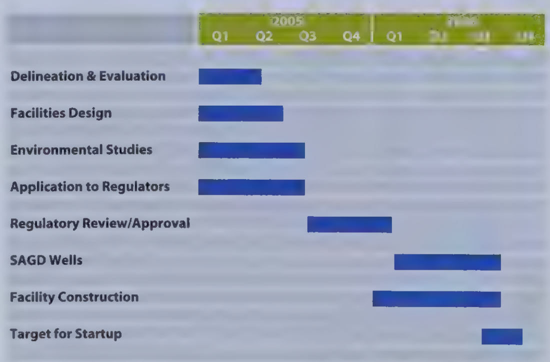
Great Divide has other identifiable risks, including the timing of a regulatory decisions, inflationary pressures on capital and subsequently operating costs, especially as other projects emerge, technological risk, bitumen pricing and marketing risk. In the short run we have seen the widening of price differentials for lower quality heavy oil. This and access to markets, together with availability of suitable refining capacity, will be issues to be addressed and managed as the project evolves in the next year or so.

Preserving per share value, through timely equity financings or partnering to raise the required capital to proceed with construction and drilling, will be a high priority for Connacher's management and board of directors throughout the year. Obviously the less dilution experienced, the greater the potential upside per share value that will accrue to shareholders. This objective must be balanced off against financial market risk and such factors as product price fluctuations, including differential swings. To the extent some form of quality differential hedging can be achieved, risk should be lowered for the project and for shareholders. Connacher's volumes are too small on a stand alone basis to support an upgrader, but various alternatives to integrate are under consideration. The projected volumes are also consequential enough to open the possibility of both upstream and downstream alliances.

If Pod One is developed and onstream, the cash flow capacity combined with its associated loan value could have the potential to finance additional Pod developments, thereby minimizing future equity dilution.

As has occurred with the share price of other oil sands project companies, under normal market conditions Connacher anticipates its equity price will increasingly reflect the value of the current and incremental production as startup is approached. Benchmarks along the way which will attract and sustain investor interest will likely include core hole results, Pod size, reserve or resource estimates, the application to the EUB and subsequent approvals, when and if received.

Pod One Drilling Schedule

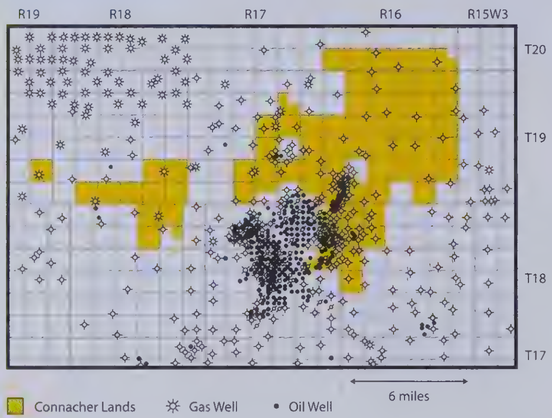


CONVENTIONAL ASSETS

Battrum, Saskatchewan

Connacher holds approximately 43,000 net undeveloped acres in the Battrum and Battrum North regions of Southwest Saskatchewan.

Battrum, Saskatchewan



The company currently produces approximately 550 bbl/d of medium gravity crude, primarily from the Roseray Formation in this region. The proved and probable reserve base was estimated to be 2.2 million barrels at December 31, 2004.

During 2004 Connacher sold its shallow gas in the area but retained the deeper rights. Also, 2D seismic was acquired and a 3D seismic program was completed over a portion of Connacher's acreage. Detailed engineering studies and subsequent field initiatives enabled the growth of Battrum production during the year, more than offsetting declines without any drilling.

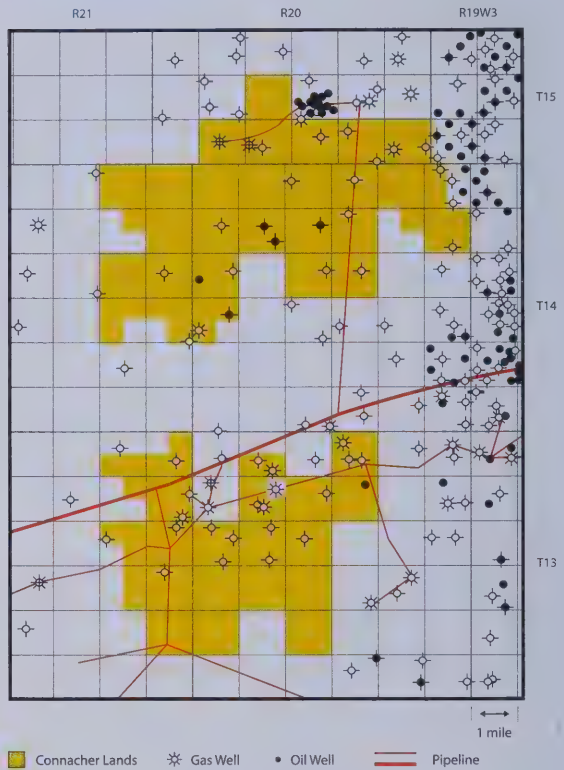
Up to five wells are under consideration for 2005 and Connacher continues to evaluate the merits of an ASP (Alkaline Surfactant Polymer) pilot flood on a portion of Unit 4 at Battrum.

While widening differentials affected netbacks in late 2004, this property remains a core source of cash flow and future growth for the company.

Tompkins, Saskatchewan

Connacher earned and now owns approximately 17,000 net acres of well-positioned petroleum and natural gas rights in the Tompkins region of Southwest Saskatchewan. The company drilled 10 farm-in wells in late 2003 and early 2004. A number of indicated discoveries were made, including the 5-19-14-20W3M Shaunavon oil discovery, which has already paid out. An interesting natural gas show was made in the northeast portion of the northern Tompkins block, while other leads were established in the area. Additional seismic and drilling is planned for the region in 2005.

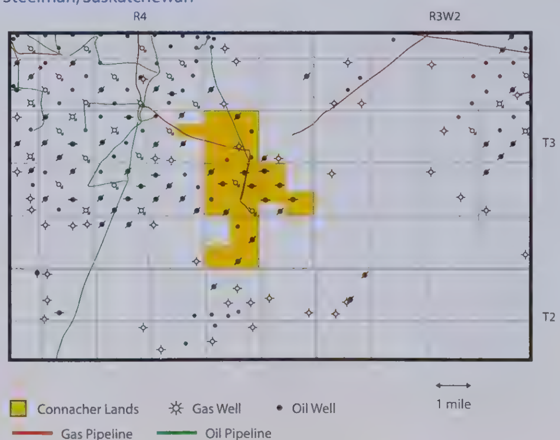
Tompkins, Saskatchewan



Other

Connacher owns lands and reserves at Steelman, Saskatchewan and scattered minor interests in other areas. Some new work is scheduled on these properties, possibility with joint venture partners, but results are not expected to materially impact the company.

Steelman, Saskatchewan



INTERNATIONAL

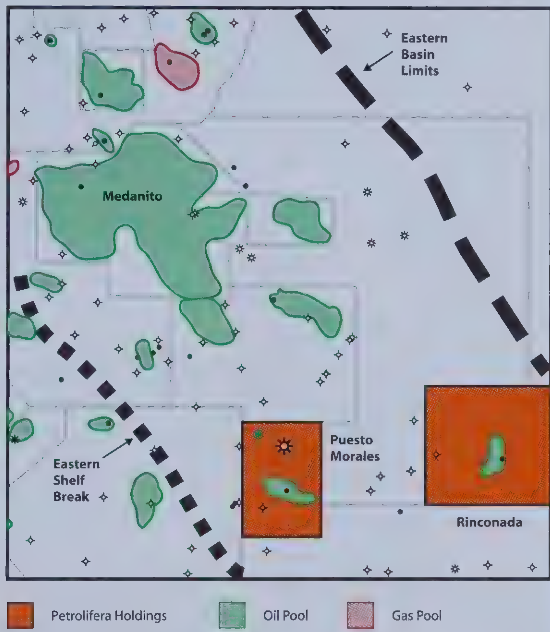
Petrolifera Petroleum Limited

Gary D. Wine
President, Petrolifera

With its main focus on Canada, especially at Great Divide, Connacher decided to reorganize its international holdings near the end of 2004. This decision was also driven by the consensus opinion that capital markets neither recognized nor assigned much value to the company's international holdings in its share price. Management believed the interest could realize more value through its securitization, especially as it was distant, non-operated and required more capital for value enhancement.

In late November, Connacher acquired the 50 percent interest it did not already hold in the Puesto Morales/ Rinconada concession in Argentina from its joint venture operator for US $1.5 million; thereby securing the ability to assume operatorship with the resultant 100 percent working interest. Connacher then disposed of its entire interest, associated production and reserves of approximately one million boe to a newly-created subsidiary, Petrolifera Petroleum Limited, for eight million of Petrolifera's common shares from treasury and a $4 million promissory note. Simultaneously, Petrolifera raised $1.5 million from the private placement sale of five million treasury units (one share, one share purchase warrant). Of the net proceeds, $1.25 million was paid to Connacher, reducing the note to $2.75 million and Connacher's equity stake in Petrolifera to 61 percent. Petrolifera's accounts were consolidated with Connacher's at year end.

Argentina Concession



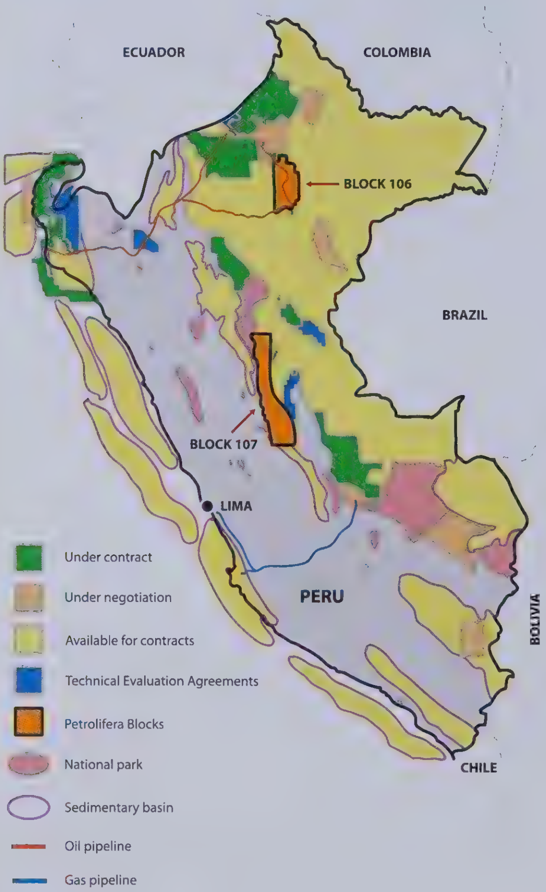
During 2004, the Argentinean properties generated approximately $1 million of revenue and $574,000 of net operating income from production of 55 bbl/d of crude oil and 710 mcf/d of natural gas, at average selling prices of $42.44 per barrel of oil and $0.67 per mcf of natural gas, respectively. Year-end reserves were estimated at 565,000 barrels of oil and 2.8 Bcf of natural gas (proved and probable) with a pre-tax 10 percent present worth of $10.9 million. Possible reserves were assigned a further 288 thousand boe with a 10 percent present worth of $3.2 million.

Under the terms of the financing and creation of Petrolifera, Connacher presently manages its affairs pursuant to a management contract.

In early 2005, Petrolifera commenced a 140 square-kilometre 3D seismic program over significant portions of the Puesto Morales and Rinconada blocks which comprise the 95,000 acre concession. The seismic program was completed in February 2005. Processing is underway and interpretation is expected to result in the confirmation and selection of at least five new locations to be drilled in 2005. With success, extensive follow-up drilling is contemplated as the concession has only seen one new exploratory well in the past thirty years and only has 12 producing wells, or about one well per eight thousand acres. It is underexplored and underexploited. Oil and natural gas in the Upper Jurassic Quintuco and Sierras Blancas Formations are the main objectives.

In January, 2005 representatives of Connacher and Petrolifera visited Peru and were successful in qualifying to acquire two new significant licenses covering over five million acres in the Maranon and Ucayali Basins, onshore Peru. The licenses will be owned by Petrolifera once they are formally awarded. In exchange for its support and guarantees, which were fundamental to securing the licenses, Connacher will receive a 10 percent carried working interest in each license through the drilling of the first well.

Peru Blocks



Block 106 in the Maranon Basin comprises approximately two million acres and offsets or surrounds numerous oilfields in the region, including the 200 million barrel Corrientes Field. The block is in northern Peru's jungle, where it is bisected by an oil pipeline with approximately 60,000 bbl/d of spare capacity. Numerous leads and prospects have already been identified on the block. A US $25 million work program over a seven year exploration period was negotiated with no mandatory drilling required until year four, although drilling is likely to occur much sooner. If commerciality is achieved, production licences are 30 years for oil and 40 years for natural gas.

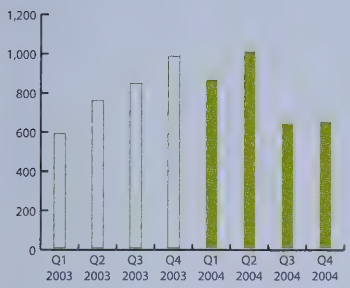
Block 107 in the Ucayali Basin of southern Peru is on the trend with and has prospects similar to the giant Camisea complex. Perupetro, the Peruvian state agency, has assigned Camisea reserves of 16.4 Tcf of natural gas and approximately 850 million barrels of liquids. The field came on stream in late 2004 with natural gas now being delivered to Lima, Peru under a gasification program. Liquid natural gas (LNG) exports are also being planned. This block carries work commitments of only $15 million with no mandatory drilling until year seven. With infrastructure now established and large fold and thrust belt potential similar to the frontal foothills of western Canada, this huge land block represents an extraordinary opportunity for Petrolifera.

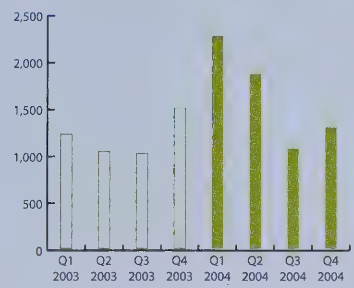
To finance planned drilling in Argentina and early activity in Peru, Petrolifera completed a $7 million equity financing in March 2005. This also enabled Petrolifera to further reduce its indebtedness to Connacher by $2 million. Together with available cash flow from Argentina, Petrolifera now has the funds to conduct an anticipated 2005 capital budget of $6.2 million, including 3D seismic and up to five anticipated wells in Argentina. Successful drilling and planned Peru activity will lead to further capital requirements in 2005 and later. If market conditions remain amenable, Petrolifera intends to go public in 2005 to raise this capital.

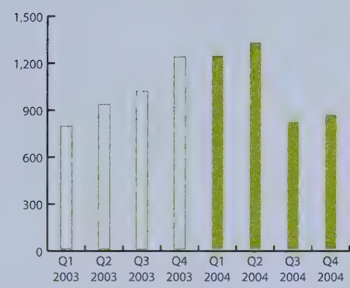
In conjunction with the financing, Petrolifera appointed an experienced and highly-qualified geologist, Mr. Gary Wine, to the position of President. Connacher's President is Executive Chairman of the company.

Connacher will continue to manage the affairs of Petrolifera, will retain significant board representation and is the largest Petrolifera shareholder.

Connacher has experienced considerable value enhancement and cash recovery since the reorganization of its foreign assets was initiated in late 2004. Further appreciation is anticipated if the quality and potential of Petrolifera's holdings is realized.







Connacher's 2004 production rose seven percent over last year; oil production was essentially flat after mid-year property sales, while natural gas sales rose 36 percent.

Of total oil production, 93 percent was in Canada and seven percent was in Argentina. Natural gas sales were more balanced, with 56 percent in Canada and 44 percent in Argentina.

Light and medium gravity crude oil sales in Canada and Argentina were 79 percent of total oil sales, with 21 percent heavy oil in Canada. On a boe basis, crude oil accounted for 74 percent of total production and natural gas sales represented 26 percent.

Connacher's 2004 objective was to lighten its product mix such that natural gas became around 50 percent of production with light and medium crude at 35 to 40 percent and heavy oil the remainder. The sale of Cabri, Saskatchewan natural gas properties and heavy oil properties located at Islay and Lloydminster, Alberta for cash to reduce debt altered this plan.

Connacher's oil production grew quickly throughout the first half of 2004, reaching its peak in the second quarter. Much of our capital spending in early 2004 was on natural gas drilling, completions, facilities and workovers which made an impact in that period. Significant production increases were primarily at Cabri earlier in the year. Connacher's second half 2004 capital program was influenced by our debt reduction mode.

2004 Average Daily Production

	Q1	Q2	Q3	Q4	Full Year
Oil (bbl/d)					
Islay, Alberta	266	378	30	-	167
Battrum, Saskatchewan	505	491	485	516	499
Steelman, Saskatchewan	26	32	25	19	25
Tompkins, Saskatchewan	14	54	47	38	38
Argentina	48	49	49	73	55
TOTAL	859	1,004	636	646	785
Natural Gas (mcf/d)					
Islay, Alberta and other	334	185	53	155	182
Steelman, Saskatchewan	33	27	-	29	22
Cabri, Saskatchewan	1,373	1,171	289	-	704
Argentina	528	477	726	1,106	711
TOTAL	2,268	1,860	1,068	1,290	1,670
Equivalent barrels (boe/d) (1)					
Islay, Alberta	322	409	39	25	198
Battrum, Saskatchewan	505	491	485	516	499
Steelman, Saskatchewan	32	37	25	23	29
Tompkins, Saskatchewan	14	54	47	38	38
Cabri, Saskatchewan	229	195	48	4	117
Argentina	136	129	170	255	173
TOTAL	1,237	1,314	814	816	[illegible]

(1) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl.

Reserves

At year end, Connacher's crude oil and natural gas reserves were primarily located in Southwest Saskatchewan, at Great Divide, Alberta and at Puesto Morales in the Neuquen Basin in Argentina. DeGolyer and MacNaughton Canada Limited ("D&M"), independent Petroleum Consultants of Calgary, Alberta, evaluated the company's reserves as at December 31, 2004 in a report dated March 2, 2005. Their report included an evaluation of proved, probable and possible reserves. The following table summarizes the D&M report, which was prepared using assumptions and methodology guidelines outlined in the "Canadian Oil and Gas Evaluation Handbook" and in accordance with NI 51-101.

Under NI 51-101, proved reserve assignments are based on a 90 percent probability that total quantities recovered will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case and are based on a 50 percent probability that they will equal or exceed estimates. The new standard provides for a more conservative evaluation of proved and probable reserves, particularly on new wells where production history has not yet been established. The change to proved and probable reserve definitions implemented by NI 51-101 for the year ended December 31, 2003, may make reserve quantity and reserve valuation comparisons to prior years difficult. Management believes the most meaningful comparison of the current year's proved plus probable reserves would be to "established reserves" of prior years (being proved plus 50 percent probable) for years prior to 2003.

Connacher's proved and probable reserves total 3.3 million barrels of crude oil and liquids and 3.5 bcf of natural gas. D&M estimates these reserves will generate $53 million of future net revenue before income tax but after royalties, capital expenditures and abandonment costs, net of salvage value, with a 10 percent present

Remaining Reserves and Future Cash Flow
Forecast Price Case at December 31, 2004
Company Share

	Remaining Reserves						Future Net Revenue (4,5,6)	
	Crude Oil		Natural Gas		NGLs		Undiscounted	Discounted
Reserve Category	Gross (1) stb	Net (2) stb	Gross (1) mmcf	Net (2) mmcf	Gross (1) bbl	Net (2) bbl	$000	at 10% $000
Proved Developed								
Producing	1,338,726	1,097,473	1,376	1,353	2,619	1,848	20,597	15,411
Non-Producing	-	-	161	142	-	-	550	478
Total Proved Developed	1,338,726	1,097,473	1,537	1,495	2,619	1,848	21,147	15,889
Proved Undeveloped	433,697	382,782	294	294	-	-	6,229	3,733
TOTAL PROVED	1,772,423	1,480,255	1,831	1,789	2,619	1,848	27,376	19,662
Probable	1,480,795	1,242,075	1,686	1,625	899	628	25,461	13,619
TOTAL Proved & Probable	3,253,218	2,722,330	3,517	3,414	3,518	2,476	52,837	33,241
Possible(3)	52,683,366	45,830,958	701	691	118	103	411,571	141,823
TOTAL Proved & Probable & Possible	56,206,584	48,553,288	4,218	4,105	3,636	2,579	464,408	175,064

(1) Before royalty deduction, net to company interest.
(2) After royalty deduction, net to company interest.
(3) Possible reserves are those reserves less certain to be recovered than probable reserves. There is at least a 10 percent probability that the quantities actually recovered will exceed the sum of the estimate of proved plus probable plus possible reserves.
(4) The values do not necessarily represent the fair market value.
(5) Including ARTC.
(6) Before income taxes and indirect costs and after capital costs and future abandonment costs net of salvage value.
(7) Includes 100 percent of Petrolifera's Argentinean reserves. Connacher owned 61 percent of Petrolifera at December 31, 2004.
(8) May not add due to rounding.

Reserve Reconciliation (1,2)
2004 Year End

	Oil and NGLs (mbbls)				Natural Gas (mmcf)				Equivalent (mboe) (3)			
	Prov.	Prob.	Poss.	Total	Prov.	Prob.	Poss.	Total	Prov.	Prob.	Poss.	Total
At December 31, 2003	2,174	1,974	1,317	5,465	5,462	3,091	1,004	9,557	3,084	2,489	1,484	7,058
Discoveries	104	104	51,753	51,961	-	-	-	-	104	104	51,753	51,961
Revisions of Prior Estimates	279	(277)	(108)	(106)	392	(128)	(475)	(211)	344	(298)	(187)	(141)
Acquisitions	150	121	92	363	770	604	289	1,663	278	222	140	640
Dispositions	(645)	(441)	(101)	(1,187)	(4,199)	(1,883)	(117)	(6,199)	(1,345)	(755)	(121)	(2,220)
Production	(287)	-	-	(287)	(593)	-	-	(593)	(386)	-	-	(386)
At December 31, 2004	1,775	1,481	52,953	56,209	1,831	1,685	701	4,218	2,079	1,762	53,069	56,912

(1) May not add due to rounding.
(2) Calculated based on forecast price case as at December 31, 2004.
(3) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf: 1bbl.

worth of $33 million. Reserves and future net revenue estimates include 100 percent of Petrolifera's reserves in Argentina as Connacher presents consolidated accounts at year end. These represent approximately 26 percent by volume and 33 percent of the 10 percent present worth assigned to Connacher's total reserves. Accordingly, Petrolifera's minority shareholders indirectly owned 10 percent by volume and 13 percent of the estimated 10 percent present worth of Connacher's reserves.

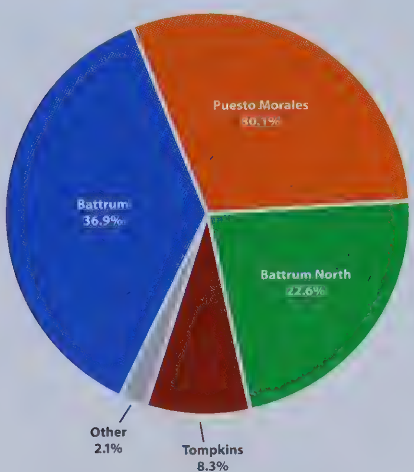
D&M also estimates that Connacher's share of the total undiscounted capital required and abandonment costs provided for in their estimate of future cash flow is as follows:

Reserve Category	Capital Costs	Abandonment Costs
	($000)	($000)
Total Proved	4,162	3,123
Probable	4,517	545
Total Proved and Probable	8,679	3,668
Possible	236,663	1,332
Total Proved, Probable and Possible	245,342	5,000

These expenditures are forecast to occur on a year-by-year basis, as required, over the life of the company's properties and are deducted prior to the calculation of undiscounted and discounted future cash flow.

The report estimates 68 percent of the company's future net revenue from proved and probable reserves is located in Canada. The balance is located in Argentina. On a proved, probable and possible basis, Canada represents 95 percent of future net revenue due to the forecast impact of Great Divide.

Percentage Distribution of 10% Present Worth of Total Proved Reserves, by Area



Based on fourth quarter 2004 production (861 boe/d), Connacher's reserve life index for proved reserves (2.1 million boe) was 6.6 years and 12.2 years for proved and probable reserves (3.8 million boe). In 2004, Connacher sold 2.1 mmboe of proved and probable reserves for approximately $17.6 million, at $8.38 per boe or approximately $35,200 per flowing boe. Caution should be used by shareholders in assessing these numbers due to the conversion of natural gas to barrels of oil equivalent at six mcf per barrel.

LAND

Connacher holds various interests in approximately 59,109 gross hectares (147,773 gross acres) of undeveloped petroleum and natural gas rights and oil sands leases in Alberta and Saskatchewan. No oil and natural gas reserves have been assigned to this property. The company's average interest in its undeveloped acreage is approximately 92 percent.

In a report dated February 18, 2005 prepared by Seaton-Jordan & Associates Ltd., (Seaton-Jordan), independent mineral management consultants of Calgary, Alberta, a fair value of $6,801,118 or approximately $115 per gross hectare was assigned to Connacher's non-reserve oil and gas properties. This equates to approximately $46 per gross acre. In determining the market value, Seaton-Jordan based their evaluation on the following factors:

1. The acquisition cost, provided that there have been no material changes in the unproved property, the surrounding properties, or the general oil and gas climate since the acquisition;
2. Recent sales by others of interests in the same unproved property;
3. Terms and conditions, expressed in monetary terms, of recent farm-in agreements;
4. Terms and conditions, expressed in monetary terms, and of recent work commitments related to the unproved property; and
5. Recent sales of similar properties in the same general area.

This complies with the Securities Commission Standards of Disclosure as described in paragraph (a), subsection (2), Section 5.10 of NI 51-101.

Connacher did not commission an evaluation of the Argentinian undeveloped acreage. At December 31, 2004 the company own 61 percent of Petrolifera, which owned a 100 percent undivided working interest in the 95,000 acre Puesto Morales/Rinconada Concession, which is largely undeveloped.

Management's Discussion and Analysis ("MD&A")

Richard R. Kines
Vice President Finance and Chief Financial Officer

The following is dated as of March 15, 2005 and should be read in conjunction with the consolidated financial statements of Connacher Oil and Gas Limited for the years ended December 31, 2004 and December 31, 2003 as contained in the annual report. The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and are presented in Canadian dollars. Additional information relating to the company, including the company's AIF, is on SEDAR at www.sedar.com. This discussion and analysis provides management's view of the financial condition of the company and the results of its operations for the reporting periods. Information contained in this report contains forward-looking information based on current expectations, estimates and projections of future production, capital expenditures and available sources of financing. It should be noted forward-looking information involves a number of risks and uncertainties and actual results may vary materially from those anticipated by the company. These risks and uncertainties include, but are not limited to, changes in market conditions, law or governing policy, operating conditions and costs, operating performance, demand for oil and gas, price and exchange rate fluctuation, currency controls, commercial negotiations and technical and economic factors. Throughout the MD&A, per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil (6:1). The conversion is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead.

CORPORATE OVERVIEW

	2004	**2003**	**2002**
FINANCIAL			
($)			
Cash on hand (bank debt and note payable)	**3,914,181**	(12,100,000)	(2,557,806)
Shareholders' equity (1)	**40,501,988**	24,182,085	4,986,336
Total assets (1)	**46,217,113**	53,776,977	12,691,785
Total revenue	**11,215,888**	9,982,291	4,325,817
Cash flow from operations (2)	**2,409,365**	3,352,778	1,046,509
Net earnings (loss) (1)	**(2,976,411)**	4,054,778	208,220
OPERATING			
Daily production / sales volumes			
Oil (bbl/d)	**785**	789	340
Natural gas (mcf/d)	**1,620**	1,190	1,365
boe/d	**1,055**	987	568
Reserves (mboe)			
Proved	**2,078**	3,085	1,513
Probable	**1,763**	2,489	249
Possible	**53,071**	1,484	-
Total	**56,912**	7,058	1,762

(1) The 2002 and 2003 amounts have been restated to reflect the retroactive adoption of a change in accounting for Asset Retirement Obligations and Stock-based Compensation.

(2) Cash flow from operations is not a measure that has any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other companies. It is calculated on the Consolidated Statement of Cash flows.

(3) The reserve estimates for 2004 and 2003 were prepared in accordance with National Instrument 51-101 (NI 51-101). Under NI 51-101, proved reserve assignments are based on a 90 percent certainty that total quantities recovered will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case and are based on a 50 percent certainty that they will equal or exceed estimates. Proved plus probable plus possible reserves have a 10 percent probability that they will equal or exceed estimates. Proved plus probable reserve estimates for 2004 and 2003 are comparable to proved plus one-half probable (or "established reserves") for 2002 and prior years.

(4) No dividends were declared by the company in the last three years.

Over the past three years, Connacher's management has selectively acquired oil and gas properties and prospective acreage to build shareholder value. In its early stage of development, the company focused on heavy oil properties (at Islay/ Lloydminster, Alberta) because they could be acquired on favorable terms and because of management's expertise and success in developing these types of assets.

In 2003 the company acquired lighter oil production (at Battrum in Southwest Saskatchewan) and prospective natural gas acreage (at Cabri in Southwest Saskatchewan) where 59 gross (57 net) wells were drilled. However, despite encouraging test results, disappointing production results ensued. As a consequence, debt levels increased and 2004 became a year of rebuilding. In July 2004 the heavy oil properties in Alberta and the Cabri natural gas wells, reserves and associated shallow petroleum and natural gas rights were sold for gross proceeds of $17.8 million, which was used to repay indebtedness and improve working capital. In November and December 2004 the company raised $21.3 million of new equity through the sale of common shares from treasury and finished the year with no net debt and $3.9 million of cash balances.

Despite the challenges of 2004, during the year Connacher established a new project called Great Divide in Alberta's oil sands region. Also, international holdings were reorganized into a new company, Petrolifera Petroleum Limited.

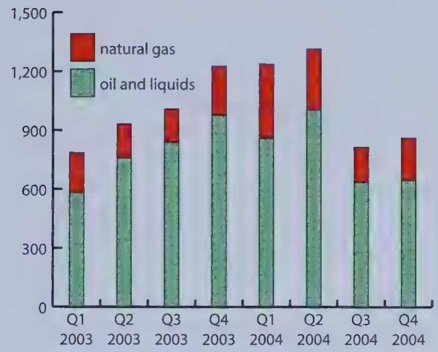
A more detailed analysis of the year's results is presented below.

REVENUE, PRODUCTION AND PRICING

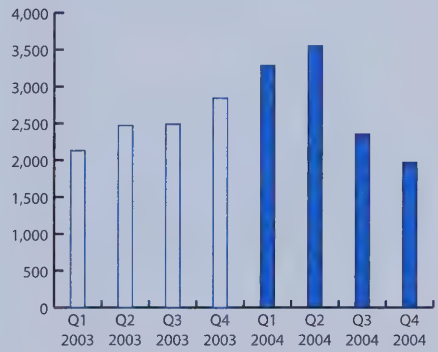
Results for 2004 were significantly affected by the disposition of producing oil and gas properties in July. These property sales represented approximately 500 boe/d, or 40 percent of the company's daily production. Notwithstanding this, total revenue for the year increased by 12 percent to $11.2 million compared to $10.0 million in 2003, on a seven percent increase in sales volume and an increase in overall product pricing of five percent from the prior year. Canadian revenues were $10.2 million, up 11 percent from $9.2 million in 2003, while Argentinean revenues were up 45 percent to $1,031,000 from $709,000 in 2003. The increase in Argentina is a result of higher product pricing and increased volumes, in part as a result of purchasing the operator's 50 percent working interest near year end 2004.

Prior to the property sales in July, oil and gas production and sales volumes had continuously increased over thirteen consecutive quarters, reaching 1,324 boe/d in the second quarter of 2004. However, quarterly production declined to 814 boe/d in the third quarter and 861boe/d in the fourth quarter of 2004 as a result of the sales. Since recapitalizing the company late in 2004, the company has adopted a measured capital expenditure program, the results and benefits of which may take several quarters to realize.

Quarterly Production (boe/d)



Quarterly Revenue ($000)



Production and Pricing

	2004	2003	2002
Daily production / sales volumes			
Oil – bbl/d			
Canada	730	741	294
Argentina	55	48	46
Total	**785**	**789**	**340**
Natural Gas –mcf/d			
Canada	910	633	811
Argentina	710	557	554
Total	**1,620**	**1,190**	**1,365**
boe – boe/d (1)			
Canada	881	847	429
Argentina	174	140	139
Total	**1,055**	**987**	**568**
Product pricing			
Oil – per bbl			
Canada	$ 30.59	$ 29.54	$ 24.22
Argentina	$ 42.44	$ 37.74	$ 32.22
Average	$ 31.42	$ 30.03	$ 25.30
Natural gas – per mcf			
Canada	$ 5.92	$ 5.34	$ 3.49
Argentina	$ 0.67	$ 0.23	$ 0.49
Average	$ 3.62	$ 2.95	$ 2.28
boe – per boe (1)			
Canada	$ 31.44	$ 29.85	$ 23.19
Argentina	$ 16.24	$ 13.72	$ 12.72
Average	$ 28.95	$ 27.56	$ 20.64

(1) All references to barrels of oil equivalent are calculated on the basis of 6 mcf: 1 bbl.

World oil prices strengthened in 2004; WTI rose over 30 percent to average US $41.44 per barrel of crude oil. The continued strengthening of the Canadian dollar, however, had the effect of reducing Canadian dollar sales. Throughout most of the year the Canadian dollar was strong, closing at US $0.83 compared to US $0.77 at December 31, 2003 for an increase of eight percent. Due to this strength, widening differentials, hedging activity and the impact of price controls in Argentina, Connacher's average crude oil price for 2004 only increased five percent to $31.42 per barrel.

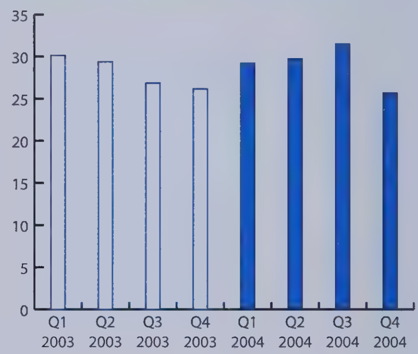
Realized Canadian natural gas prices were also higher in 2004, rising 11 percent over the prior year. Argentinean gas prices improved somewhat in the year (averaging $0.67 per mcf compared to $0.23 per mcf in 2003), as the Argentinean government permitted price increases, although selling prices are still substantially below North American averages. The corporate average price per mcf rose 23 percent.

Connacher's realized price per boe in 2004 rose five percent to $28.95 from $27.56 last year.

To mitigate the vagaries of volatile price swings in the market for crude oil, which are beyond the control of the company, management has employed a modest strategy to fix the selling price of a portion of its domestic oil sales. Accordingly, in 2004, the company renewed its heavy crude oil sales contract for 200 bbl/d for one year from March 1, 2004 until February 28, 2005 at a WTI base price of CDN $42.67 before quality differential adjustments. Effective April 1, 2004 the 250 bbl/d Battrum medium gravity crude oil sales contract was also renewed for one year at a WTI reference price of CDN $44.08 before premium adjustment and quality differential.

The company's reported revenues include gains and/or losses realized on the oil sales contracts; they are not separately reported in the consolidated financial statements. Since entering into the 2004 contracts, world oil prices strengthened. As a result, crude oil revenues realized in 2004 were lower than would have been reported had the company not entered into the 2004 contracts by approximately $1 million. In 2003 weaker world oil prices had the opposite result; 2003 revenues were higher by approximately $200,000 than they would have been without the forward sales contracts.

Quarterly Revenue per boe ($/boe)



ROYALTIES

Royalties represent charges against production or revenue by governments and landowners. Royalties in 2004 were $2.1 million ($5.54 per boe, or 19 percent of oil and gas revenue) compared to $1.8 million in 2003 ($4.98 per boe, or 18 percent of oil and gas revenue). From year to year royalties can change slightly based on changes to the weighting in the product mix which are subject to different royalty rates. The change from 2003 to 2004 reflects this set of circumstances.

Royalties

	2004		2003	
	Total	Per boe	Total	Per boe
Canada	$ 1,997,278	$ 6.19	$ 1,722,900	$ 5.58
percentage of total oil and gas revenue	19.7%		18.7%	
Argentina	$ 141,638	$ 2.23	$ 71,540	$ 1.39
percentage of total oil and gas revenue	13.7%		10.1%	
Total	$ 2,138,916	$ 5.54	$ 1,794,440	$ 4.98
percentage of total oil and gas revenue	19.1%		18.0%	

OPERATING EXPENSES AND OPERATING NETBACKS

Company Operating Netbacks - combined Canada and Argentina (1)

	2004		2003		% Change 2004 - 2003	
	Total	Per boe	Total	Per boe	Total	Per boe
Average daily production (boe)	1,055		987		6.9%	
Oil and natural gas revenue	$ 11,179,404	$ 28.95	$ 9,930,717	$ 27.56	12.6%	5.0%
Other income	36,484	0.09	51,574	0.14	(29.3%)	(35.7%)
Total revenue	11,215,888	29.03	9,982,291	27.70	12.4%	4.8%
Royalties	(2,138,916)	(5.54)	(1,794,441)	(4.98)	19.2%	11.2%
Net revenue	9,076,972	23.50	8,187,850	22.72	10.9%	3.4%
Operating costs	(3,621,804)	(9.38)	(2,935,799)	(8.15)	23.4%	15.1%
Transportation costs	(143,727)	(0.37)	(115,992)	(0.32)	23.9%	15.6%
Operating netback	$ 5,311,441	$ 13.75	$ 5,136,059	$ 14.25	3.4%	(3.6%)

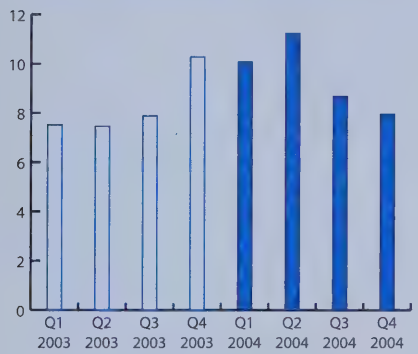
(1) Calculated by dividing related revenue and costs by total boe produced, resulting in an overall combined company netback.

Total operating expenses increased by 23 percent in 2004 to $3.6 million compared to $2.9 million in 2003. This reflected increased sales volumes, together with startup costs and production problems at Cabri in early 2004. Unit costs rose to $9.38 per boe compared to $8.15 per boe in 2003. Following the sale of the Cabri, Saskatchewan property and the higher-cost heavy oil production at Islay and Lloydminster, Alberta, unit operating costs declined in the latter months of 2004. Argentinean operating costs were relatively unchanged from last year, averaging $5.02 per boe in 2004 compared to $5.08 per boe in 2003. These lower costs in part reflect the impact of a devalued Argentinean peso relative to the stronger Canadian dollar.

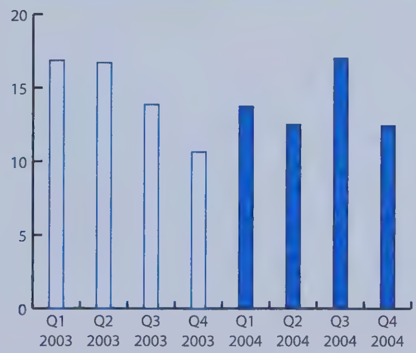
Companies are now required to separately identify transportation costs, so they are no longer netted against oil and natural gas revenue in reporting to shareholders. Accodingly, 2003 results have been restated to conform with current year presentation requirements. The increase in transportation costs in 2004 is primarily due to increased sales volumes.

Canadian netbacks per boe in 2004 were $14.69 per boe, compared to $15.25 per boe in 2003, while Argentinean netbacks rose 24 percent and averaged $8.99 per boe in 2004, compared to $7.24 per boe in 2003. These levels primarily reflect low natural gas prices compared to North America. Overall, netbacks declined four percent. Netbacks do not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measurees used by other companies. Nevertheless, Connacher's management uses netback as a performance measurement.

Operating Expenses per boe ($/boe)



Company Netback per boe ($/boe)



2004 Operating Netbacks by Country and Product

Per unit netbacks are calculated by dividing netbacks by sales volumes.

Operating netbacks by product type and by country are indicated below.

	Canada						Argentina			
	Light oil		Heavy oil		Natural gas		Light oil		Natural gas	
	Total	Per bbl	Total	Per bbl	Total	Per mcf	Total	Per bbl	Total	Per mcf
Average daily production	**563 bbl/d**		**167 bbl/d**		**910 mcf/d**		**55 bbl/d**		**710 mcf/d**	
Oil and natural gas revenue	$ 6,694,985	$ 32.49	$ 1,515,902	$ 24.75	$ 1,973,629	$ 5.92	$ 857,949	$ 42.44	$ 173,423	$ 0.67
Royalties	(1,514,098)	(7.35)	(214,890)	(3.51)	(268,290)	(0.81)	(117,822)	(5.83)	(23,816)	(0.09)
Operating and transportation costs	(1,765,777)	(8.57)	(490,991)	(8.02)	(1,189,934)	(3.57)	(265,219)	(13.12)	(53,610)	(0.21)
Netback	$ 3,415,110	$ 16.58	$ 810,021	$ 13.23	$ 515,405	$ 1.55	$ 474,908	$ 23.49	$ 95,997	$ 0.37

GENERAL AND ADMINISTRATIVE EXPENSES

Total general and administrative (G&A) expenses increased in 2004, due to increased public company costs, staffing, rent and increased provisions for non-cash stock option expenses of $181,000 (2003 - $87,000), reflecting the fair value of all stock options granted in the year. Total G&A expenses were $2.2 million in 2004 compared to $1.1 million in 2003. In 2004, G&A of $70,700 was capitalized (2003 - $204,300).

G&A of $5.69 per boe is high due to lower than expected production and sales volumes, primarily attributable to the poor production performance at Cabri and then asset sales completed in 2004. A reduction in unit costs is expected as volumes increase, especially when and if Great Divide production commences.

INTEREST AND FOREIGN EXCHANGE

Higher debt levels and slightly increased lending rates in 2004 combined to caused total interest costs to rise by 17 percent to $883,000 in the year. Of this amount, $770,000 was expensed (2003 - $756,000) and $113,000 (2003 – nil) was capitalized in respect of the Great Divide oil sands project. In late 2004 the company paid off all of its bank debt, but in the future Connacher will continue to utilize banking facilities to leverage shareholders' capital while growing the company. No debt was used in the Argentinean operations.

When translating foreign denominated financial statements and operating results, the impact of fluctuations on the Argentinean peso relative to the Canadian dollar resulted in a foreign exchange loss of $46,000 in 2004 (2003 - $45,000). The company's main exposure to foreign currency risk relates to pricing crude oil sales, which are denominated in US dollars. However, some of this risk

has been mitigated by fixing the sales price of a portion of the company's crude oil production in Canadian dollar-denominated oil sales contracts.

DEPLETION, DEPRECIATION AND ACCRETION ("DD&A")

DD&A is calculated using the unit-of-production method based on total estimated proved reserves. DD&A in 2004 was $6.9 million, an 85 percent increase over last year. This increase is primarily a result of a substantially higher average depletable cost base, although the seven percent increase in production was also a contributing factor. The costs of disappointing drilling programs at Cabri and Battrum in 2003 and early 2004 causes DD&A per boe to be high until significant new production and sales volumes can be added at lower finding and development costs.

Capital costs of $4.4 million (2003 – nil) related to major development projects in a pre-production state at Tompkins, Saskatchewan and at the Great Divide oil sands project have been excluded from depletable costs. No proved reserves have been assigned to those projects. Additionally, undeveloped land acquisition costs of $3.4 million (2003 – $3.4 million) were similarly excluded from the depletion calculation.

Included in DD&A is a charge of $178,000 (2003 - $143,000) to accrete the company's estimated asset retirement obligation. These charges will continue to be necessary in future to accrete the currently booked discounted liability of $2.9 million to the estimated total undiscounted liability of $5.6 million over the estimated remaining useful life of the company's oil and gas properties.

REORGANIZATION OF ARGENTINEAN OPERATIONS

In 2004 the company reorganized its Argentinean oil and gas properties by acquiring the non-owned 50 percent operated interest in an arms length transaction from its joint venturer. Late in 2004, Connacher incorporated a subsidiary, Petrolifera Petroleum Limited ("Petrolifera") and sold its Argentinean assets to Petrolifera for eight million common shares from Petrolifera's treasury and a $4 million promissory note. Concurrent with acquiring the Argentinean assets from Connacher, Petrolifera raised $1.5 million and used $1.25 million of those funds to partially settle the note. The financing had the effect of reducing Connacher's equity interest in Petrolifera from 100 percent to 61 percent, as Connacher did not participate in the financing. The 39 percent reduction in its holding resulted in a gain to the company of $825,000, after tax. In March 2005 Petrolifera raised $7 million through an equity private placement and paid $2 million of the proceeds to Connacher, reducing the balance of the note to $750,000. Connacher now holds a 40 percent equity interest in Petrolifera. If market conditions permit, a further public financing and a listing on a recognized stock exchange are contemplated by Petrolifera in 2005.

INCOME APPLICABLE TO NON-CONTROLLING INTERESTS

The non-controlling interests charge of $8,900 reported in 2004 (2003 – nil) represents the non-controlling shareholders' equity share of the income of the consolidated subsidiary, Petrolifera.

TAXES

The current income tax provision of $115,000 primarily relates to the taxes payable in Argentina as a result of the sale of the Argentinean assets. There are no Canadian cash taxes payable, as the company has substantial Canadian tax pools to shelter its income. The $48,000 recovery of current taxes in 2003 relates to taxes recovered in Argentina.

A future tax recovery of $372,000 was recorded in 2004. In 2003 the company reorganized the tax benefit of its previously unrecognized tax assets, resulting in a recovery of $4.5 million.

At December 31, 2004 the company had approximately $43 million of deductible tax pools and operating loss carry-forwards in Canada to shelter future taxable income. These tax pools will be supplemented with ongoing capital expenditures.

CEILING TEST

Oil and gas companies are required to compare the recoverable value of their oil and gas assets to their recorded carrying value at the end of each reporting period. Excess carrying values over ceiling value are to be written off against earnings. No writedown was required for any reporting period in 2004, 2003 or 2002.

NET EARNINGS AND SHARES OUTSTANDING

For 2004 the company reported a net loss of $3.0 million, which equates to a loss of ($0.06) per basic and diluted share outstanding. This compares to net earnings of $4.0 million or $0.13 per basic share and $0.12 per diluted share outstanding for 2003, as restated.

Reported 2003 net earnings profit have been restated to reflect the retroactive impact of adopting the CICA's new accounting policies in 2004 for Asset Retirement Obligations and Stock-based Compensation.

The majority of the year-over-year change was the result of the negative impact of higher non-cash charges. The change in the future tax provision of $4.1 million and the change in the provision for DD&A of $3.2 million were the principal contributors to the loss reported in 2004 compared to earnings in 2003. These changes do not affect the company's liquidity.

For the year 2004, the weighted average number of shares outstanding were 50,907,942 (2003 – 32,362,110) and diluted shares outstanding, as calculated by the treasury stock method, were 53,328,551 (2003 – 35,333,124).

As at March 15, 2005, the company had the following securities issued and outstanding:

- 92,652,500 common shares;
- 5,300,525 share purchase warrants; and
- 3,748,600 share purchase options.

Details of the exercise rights and terms of the warrants and options are noted in the Consolidated Financial Statements, included in this annual report.

Net Earnings

	2004		2003 (restated)		% Change	
	Total	Per boe	Total	Per boe	Total	Per boe
Operating netback	$ 5,311,441	$ 13.75	$ 5,136,059	$ 14.25	3.4%	(3.5%)
General & administrative	(2,197,239)	(5.69)	(1,121,279)	(3.11)	96.0%	83.0%
Interest	(770,026)	(1.99)	(755,566)	(2.10)	1.9%	(5.2%)
Foreign exchange loss	(45,524)	(0.12)	(45,190)	(0.12)	-	-
Depletion, depreciation and accretion	(6,876,110)	(17.81)	(3,707,429)	(10.29)	85.5%	73.1%
Gain on reorganization of Argentinean operations	1,353,199	3.51	-	-	-	-
Non-controlling interest	(8,930)	(0.02)	-	-	-	-
Taxes	256,778	0.66	4,548,183	12.62	(94.3%)	(94.8%)
Net earnings (loss)	$ (2,976,411)	$ (7.71)	$ 4,054,778	$ 11.25		

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations and cash flow per share do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Nevertheless, Connacher's management uses cash flow from operations and cash flow per share as a performance measurement. The calculation of cash flow from operations is shown on the Consolidated Statement of Cash Flows.

Cash flow from operations in 2004 was $2.4 million ($0.05 per basic and diluted share) compared to $3,353,000 ($0.10 per basic and diluted share) in 2003. The change reflects the disappointing production performance at Cabri, lower second half production after property sales and the impact of higher costs, including fixed costs, over a reduced revenue base.

Cash flow per boe was $6.24 in 2004 compared to $9.31 in 2003. This represents 22 percent of the average company selling price in 2004 compared to 34 percent in 2003.

Capital expenditures before dispositions in 2004 totaled $17.6 million. A breakdown of the expenditures follows:

- $1.8 million to acquire producing oil and gas properties;
- $1.8 million for land acquisition and retention;
- $12.1 million for drilling, completions, equipping and facilities; and
- $1.9 million for seismic, abandonment and other.

In 2004 the Company drilled a total of 25 gross wells (25 net wells). These included seven wells at Cabri and six wells at Tompkins (in Southwest Saskatchewan) and 11 core holes on the company's oil sands property at Great Divide, Alberta. Core holes are drilled to gather information about the underlying reservoir, and are not designed for completion or production. The Cabri wells were sold in the July 2004 property sale.

Offsetting these expenditures were proceeds of disposition of $17.6 million, primarily comprised of the sales of the Cabri and Islay/Lloydminster properties completed in July.

Great Divide Oil Sands Project, Northern Alberta

The company holds a 100 percent working interest in 64,640 acres of oil sands leases in northern Alberta. To date, the focus has been on a four section tract ("Pod One") on which approximately $7 million has been incurred to adequately delineate the oil bearing reservoir of this portion of the leases. Most of these costs were incurred in late 2004 and early 2005, on time and on budget. Upon completion of ongoing engineering studies, submissions will be filed with regulatory authorities seeking approval to allow the company to develop a 10,000 bbl/d steam assisted gravity drainage ("SAGD") project in 2006. Capital development costs for Pod One are being developed and are expected to reach up to $200 million. Approximately two thirds of these forecast expenditures (subject to further refinement) are anticipated to be for surface facilities with the balance of the costs to drill the initial horizontal well pairs. Management and the Board of Directors are assessing the best means to finance this project, including maintaining a 100 percent working interest and raising new equity and debt or giving up a portion in a joint venture arrangement.

Tompkins Natural Gas Project, Southwest Saskatchewan

In late 2003 and in early 2004, the company drilled and cased nine natural gas wells and one oil well. Costs incurred to date have been on budget. The oil well has been producing throughout 2004 and has paid out. The natural gas wells require further evaluation and additional wells will likely be required to establish a sufficient reserve base for commercial exploitation. The company was financially constrained for most of 2004 and deferred this activity, but now has the financial capacity to complete the project, pending availability of services and surface access to the leases due to environmental sensitivity.

FINANCING ACTIVITIES

Operational disappointments at Cabri created a liquidity problem in early 2004, as anticipated cash flow from the development drilling program at Cabri did not materialize to service increased net debt. Management implemented and executed a financial reorganization that included the sale of the Cabri natural gas property and the Islay/Lloydminster heavy oil properties. The sales were completed in July 2004 for gross proceeds of $17.6 million, all of which was applied to reduce indebtedness and improve working capital. In November and December 2004 the company raised $21.3 million of new equity and also sold its Argentinean oil and gas properties to Petrolifera. The company ended the year with no net debt and $3.9 million of cash balances. Additionally, at year end the company had unused banking lines of credit totaling $8.6 million.

Other than the financing required for the capital costs of the Great Divide Oil Sands Project, management believes that available cash and banking lines of credit together with operating cash flow will provide sufficient funding for working capital purposes and for the company's planned capital program in the short term. In the longer term, it may be necessary to access additional capital in the equity markets. Except for a commitment to incur $400,000 of capital expenditures on behalf of a joint venturer in the Tompkins area, the company's capital program is entirely discretionary and may be expanded or curtailed based on drilling results. This is reinforced by the fact that Connacher operates most of its wells and holds an average 92 percent working interest.

Proceeds of the 2004 financing were utilized as follows :

	As stated at the time of the financing	As actually applied
Gross proceeds	$ 21,274,000	$ 21,274,000
Agents commissions and issue costs	1,624,000	1,624,000
Net proceeds	19,650,000	19,650,000
Applied to reduce indebtedness	14,364,000	14,364,000
Applied to capital program in 2004	1,372,000	1,372,000
Available for capital program in 2005	$ 3,914,000	$ 3,914,000

The 2004 financing included the issuance of flow-through shares for proceeds of $7,024,000. Resource expenditures of $7,024,000 were renounced to investors effective December 2004. The company has until the end of 2005 to incur the costs. By mid-March, the company had fulfilled approximately $4.5 million of this obligation. The remaining $2.5 million obligation is expected to be satisfied upon the completion of management's planned capital program and is expected to be funded from currently available cash balances and operating cash flow.

RELATED PARTY TRANSACTIONS

In 2004 the company was billed a total of $250,800 (2003 - $200,000) for legal fees provided by a law firm in which a director and the company's corporate secretary are partners.

During 2003 the company's President & Chief Executive Officer (CEO) and the company's Chief Operating Office (COO) provided their services to the company through their private management services companies. During 2003 the COO became a salaried employee. A total of $167,200 was paid to the President & CEO and the COO for consulting services they provided to the company. Effective January 1, 2004, the President & CEO also became a salaried employee.

Transactions with these parties occurred within the normal course of business, in amounts agreed by the parties.

QUARTERLY RESULTS

Three Months Ended	2003 Mar 31	2003 Jun 30	2003 Sept 30	2003 Dec 31	2004 Mar 31	2004 Jun 30	2004 Sept 30	2004 Dec 31
Financial Highlights ($000 except per share amounts) - Unaudited								
Total revenue	2,164	2,474	2,491	2,853	3,290	3,556	2,358	1,975
Cash flow from operations (1)	779	821	745	1,008	944	516	478	471
Basic, per share (1)	0.03	0.02	0.02	0.03	0.02	0.01	0.01	0.01
Diluted, per share (1)	0.03	0.03	0.02	0.02	0.02	0.01	0.01	0.01
Net earnings (loss) (2)	166	44	2,815	1,030	(689)	(1,268)	(869)	(150)
Basic, per share (2)	0.01	-	0.08	0.04	(0.01)	(0.03)	(0.02)	-
Diluted, per share (2)	0.01	-	0.07	0.04	(0.01)	(0.03)	(0.02)	-
Capital expenditures	10,768	4,272	5,715	15,015	10,391	2,603	681	3,954
Proceeds on disposal of oil and gas properties	-	-	-	-	-	89	17,564	(49)
Bank debt	10,650	12,500	13,800	12,100	20,600	23,655	7,563	-
Working capital surplus deficiency	(864)	(179)	(2,695)	(8,994)	(9,850)	(8,357)	(6,644)	3,549
Cash on hand (net debt)	(11,514)	(12,679)	(16,495)	(21,094)	(30,450)	(32,012)	(14,207)	3,549
Shareholders' equity (2)	7,447	9,718	13,613	24,486	21,655	20,933	20,217	40,502
Operating Highlights								
Production								
Natural gas (mcf/d)	1,216	1,033	1,012	1,496	2,268	1,860	1,068	1,290
Crude oil (bbl/d)	582	752	839	978	859	1,004	636	646
Equivalent (boe/d) (3)	785	924	1,008	1,228	1,237	1,314	814	861
Pricing								
Crude oil ($/bbl)	32.22	33.10	29.40	26.96	30.41	29.46	36.58	30.68
Natural gas ($/mcf)	4.03	2.18	2.35	3.02	4.42	5.11	2.21	1.29
Selected Highlights ($/boe) (3)								
Weighted average sales price	30.15	29.37	26.84	25.17	29.22	29.74	31.45	24.93
Other income	0.50	0.04	0.03	0.10	-	-	0.33	0.15
Royalties	5.78	5.20	5.08	4.23	5.37	5.95	6.06	4.64
Operating and transportation costs	7.51	7.46	7.89	10.29	10.09	11.26	8.70	7.98
Netback (4)	17.36	16.75	13.90	10.75	13.76	12.53	17.05	12.47
Common Share Information								
Shares outstanding at end of period (000)	28,717	34,082	36,512	45,903	46,153	47,368	47,668	49,627
Weighted average shares outstanding for the period								
Basic (000)	25,021	29,421	35,820	39,022	46,067	47,042	47,400	50,908
Diluted (000)	25,528	31,945	38,817	42,138	50,119	48,496	47,504	53,329
Volume traded during quarter (000)	6,031	8,342	10,027	15,045	20,706	30,188	8,880	25,256
Common share price ($)								
High	0.45	0.76	0.87	1.60	1.75	1.08	0.44	0.80
Low	0.30	0.40	0.65	0.74	0.73	0.30	0.28	0.31
Close (end of period)	0.42	0.71	0.75	1.60	0.78	0.40	0.32	0.55

(1) Cash flow from operations and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by others.
(2) Comparative 2003 figures have been restated to reflect changes in accounting policies.
(3) All references to barrels of oil equivalence is calculated on the basis of six mcf to one barrel.
(4) For detailed netbacks by product type and by country, see "Operating Expenses and Operating Netbacks", in this MD&A.

SIGNIFICANT ACCOUNTING POLICIES AND APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by the company are described below. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Changes in these judgments and estimates may have a material impact on the company's financial results and condition. The following discusses such accounting policies and is included in this MD&A to aid the reader in assessing the critical accounting policies and practices of the company and the likelihood of materially different results being reported. Management reviews its estimates regularly. The emergence of new information and changed circumstances may result in changes to estimates which could be material and the company might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

The following assessment of significant accounting policies is not meant to be exhaustive.

Oil and Gas Reserves

Under Canadian Securities Regulators' "National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. In accordance with this definition, the level of certainty should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of probable reserves, which are less certain to be recovered than proved

reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those reserves less certain to be recovered than probable reserves. There is at least a 10 percent probability that the quantities actually recovered will exceed the sum of proved plus probable plus possible reserves.

The oil and gas reserves estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the company's plans. The reserve estimates are also used in determining the company's borrowing base for its credit facilities and may impact the same upon revisions or changes to the reserves estimates. The effect of changes in proved oil and gas reserves on the financial results and position of the company is described under the heading "Full Cost Accounting for Oil and Gas Activities".

FULL COST ACCOUNTING FOR OIL AND GAS ACTIVITIES

Depletion Expense

The company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit-of-production method based on estimated proved oil and gas reserves.

Major Development Projects and Unproved Properties

Certain costs related to major development projects and unproved properties are excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These costs are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to income.

Full Cost Accounting Ceiling Test

The company is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

The ceiling test is based on estimates of reserves, production rate, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

Asset Retirement Obligations

Effective January 1, 2004, the company changed its accounting policy with respect to accounting for asset retirement obligations. Under the current accounting policy, the company is required to provide for future removal and site restoration costs. The company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings only when management is able to determine the amount and the likelihood of the future obligation.

Income Tax Accounting

The determination of the company's income and other tax assets and liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset or liability may differ significantly from that estimated and recorded by management. Recoverability of future tax assets is dependent upon sufficiency of future taxable income.

Legal, Environment Remediation and Other Contingent Matters

In respect of these matters, the company is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine if such a loss can be estimated. When any such loss is determined, it is charged to earnings. Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to earnings when warranted by circumstance.

COMMITMENTS, CONTINGENCIES, GUARANTEES, CONTRACTUAL OBLIGATIONS AND OFF BALANCE SHEET ARRANGEMENTS

The company has entered into a crude oil sale agreement with an independent integrated oil company to sell 250 bbl/d medium gravity crude oil production at CDN $44.08 (before deduction for crude oil price differential) from April 1, 2004 to March 31, 2005. Management does not intend to renew this agreement at expiry.

The company's annual commitments under leases for office premises and operating costs, field compression equipment, software license agreements and other equipment are as follows:

2005 - $475,000; 2006 - $394,000; 2007 - $374,000; 2008 - $527,000; 2009 - $521,000; thereafter - $215,000.

Additionally, the company has various guarantees and indemnifications in place in the ordinary course of business, none of which are expected to have a significant impact on the company's financial statements or operations.

The company has not entered into any off-balance sheet arrangements.

CHANGES IN ACCOUNTING POLICIES

There have been many recent changes made and proposed to Canadian and international accounting standards. In 2003, the company adopted new policies respecting recognition and measurement, disclosure of guarantees, impairment of long-lived assets and disposal of long-lived assets and discontinued operations. In 2004, the company adopted changes respecting accounting and disclosure of stock-based compensation, the new full cost method of oil and gas accounting, asset retirement obligations, and flow-through shares. The company is currently assessing the impact of the new accounting guideline on consolidation of variable interest entities, which is effective in 2005.

OUTLOOK

The company's business plan for 2005 contemplates renewed growth. To accomplish this, the company expects a measured but active capital program of oil and gas property acquisition and development drilling in Canada. Emphasis is expected to be placed on delineating and developing its Great Divide oil sands property in Alberta.

Forecast operating cash flow, available cash, possible new bank borrowings and additional equity as required will finance Connacher's expected 2005 capital spending program. Joint ventures may also be utilized.

In the past, Connacher issued guidance for its anticipated operating and financial results. The company has decided to discontinue the issuance of detailed guidance due to the difficulty in forecasting for a high growth company in a long-term business, when results could be significantly affected in the short term or quarter-to-quarter by drilling outcomes and timing, leading to increased and unpredictable volatility.

All estimates and statements which may have been issued with respect to 2005 expectations were or are forward-looking statements. This involves inherent risks and uncertainties where actual results will differ and such differences could be material. There can be no assurance Connacher will achieve the drilling results and levels of production it might assume in developing its internal 2005 capital budget and financial plan. In addition, oil and gas prices are subject to fluctuation and there can be no assurance that the prices assumed for the company's internal 2005 plan, or any variation thereof, will be attained.

BUSINESS RISKS

Connacher, being a junior oil and gas exploration, development and production company, is exposed to certain risks and uncertainties inherent in the oil and gas business. Furthermore, being a smaller independent company, it is exposed to financing and other risks which may impair its ability to realize on its assets or to capitalize on opportunities which might become available to it. Additionally, because the company has operated in various jurisdictions, it has become exposed to other risks including currency fluctuations, political risk, price controls and varying forms of fiscal regimes or changes thereto which may impair its ability to conduct profitable operations. Connacher experienced some of these developments in Argentina in the 2001-2004 period.

The risks arising in the oil and gas industry include price fluctuations for both crude oil and natural gas over which the company has limited control; risks arising from exploration and development activities; production risks associated with the depletion of reservoirs and the ability to market production. Additional risks include environmental and safety concerns.

As a relatively small concern, the company has to rely on access to capital markets for new equity to supplement internally generated cash flow and bank borrowings to finance its growth plans. Periodically, these markets may not be receptive to offerings of new equity from treasury, whether by way of private placement or public offerings. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. An increased emphasis on flow-through share financings may accelerate the pace at which junior oil and gas companies become cash-taxable, which could reduce cash flow available for capital expenditures on growth projects. Periodic fluctuations in energy prices may also affect lending policies of the company's banker, whether for existing loans or new borrowings. This in turn could limit growth prospects over the short run or may even require the company to dedicate cash flow, dispose of properties or raise new equity to reduce bank borrowings under circumstances of declining energy prices or disappointing drilling results.

The success of the company's capital programs as embodied in its productivity and reserve base could also impact its prospective liquidity and pace of future activities. Control of finding, development, operating and overhead costs per boe is an important criterion in determining company growth, success and access to new capital sources.

The company attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The company also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

Furthermore, the company generally relies on equity financing and a bias towards conservative financing of its operations under normal industry conditions to offset the inherent risks of domestic and international oil and gas exploration, development and production activities. In the past the company has entered into forward sale, fixed price contracts to mitigate reduced product price risk and foreign exchange risk during periods of price improvement, primarily with a view to assuring the availability of funds for capital programs and to enhance the creditworthiness of its assets with its lenders. While hedging activities may have opportunity costs when realized prices exceed hedged pricing, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such financing techniques.

Management's Report

To the Shareholders of
Connacher Oil and Gas Limited:

The consolidated financial statements of Connacher Oil and Gas Limited were prepared by and are the responsibility of management. The financial statements have been prepared in conformity with Canadian generally accepted accounting principles appropriate in the circumstances and include some amounts that are based on management's best estimates and judgments.

The company maintains systems of internal accounting controls designed to provide reasonable assurance that all transactions are properly recorded in the company's books and records, that policies and procedures are adhered to and that the assets are protected from unauthorized use. The systems of internal accounting controls are complemented by the selection, training and development of qualified staff.

The consolidated financial statements have been audited by the independent accounting firm Deloitte & Touche LLP whose appointment is ratified yearly by the shareholders at the annual shareholders' meeting. The independent accountants perform such tests and related procedures as they deem necessary to arrive at an opinion on the fairness of the financial statements.

The audit committee of the board of directors periodically meets with the independent auditors and management to satisfy itself that it is properly discharging its responsibilities. The independent auditors have unrestricted access to the audit committee, without management present, to discuss the results of their examination and the quality of financial reporting and internal accounting control.

Signed,
"R.A. Gusella"
President and Chief Executive Officer
Connacher Oil and Gas Limited
March 15, 2005

Signed,
"R. R. Kines"
Vice President, Finance and Chief Financial Officer
March 15, 2005

Auditors' Report

To the Shareholders of
Connacher Oil and Gas Limited:

We have audited the consolidated balance sheets of Connacher Oil and Gas Limited as at December 31, 2004 and 2003 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2004 and 2003 and the result of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Signed,
"DELOITTE & TOUCHE LLP"

Chartered Accountants

Calgary, Alberta
March 11, 2005

Consolidated Balance Sheets

CONNACHER OIL AND GAS LIMITED

December 31

	2004	2003
		(restated Notes 2 & 8)
	($)	($)
ASSETS		
CURRENT		
Cash	3,914,181	627,302
Accounts receivable	1,773,005	2,657,150
Loan receivable (Note 3)	-	135,848
Prepaid expenses	309,062	297,009
	5,996,248	3,717,309
Deposits (Note 4)	-	279,700
Property and equipment (Note 5)	36,542,595	45,177,648
Future income tax asset (Note 6)	3,678,270	4,602,320
	46,217,113	53,776,977
LIABILITIES		
CURRENT		
Accounts payable	2,446,947	12,710,892
Bank loans (Note 7)	-	12,100,000
	2,446,947	24,810,892
Asset retirement obligations (Note 8)	2,905,477	4,784,000
Deferred credits (Note 9)	353,771	-
Non-controlling interests (Note 11)	8,930	-
	5,715,125	29,594,892
SHAREHOLDERS' EQUITY		
Share capital and contributed surplus (Note 10)	39,290,819	19,794,505
Retained earnings	1,211,169	4,387,580
	40,501,988	24,182,085
	46,217,113	53,776,977

Commitments, contingencies and guarantees (Note 15).

Approved by the Board

Signed,
"S.D. McGregor"
Stewart D. McGregor, Director

Signed,
"G.W. Freeman"
Gary W. Freeman, Director

Consolidated Statements of Operations and Retained Earnings

CONNACHER OIL AND GAS LIMITED

Years Ended December 31

	2004	2003
		(restated Notes 2 & 8)
	($)	($)
REVENUE		
Petroleum and natural gas sales	11,179,404	9,930,717
Other income	36,484	51,574
	11,215,888	9,982,291
Royalties	(2,138,916)	(1,794,441)
	9,076,972	8,187,850
EXPENSES		
Operating	3,621,804	2,935,799
Transportation costs	143,727	115,992
General and administrative	2,197,239	1,121,279
Interest	770,026	755,566
Foreign exchange	45,524	45,190
Depletion, depreciation and accretion (Note 5)	6,876,110	3,707,429
Gain on reorganization of Argentinean operations (Note 11)	(1,353,199)	-
	12,301,231	8,681,255
Loss before taxes and non-controlling interests	(3,224,259)	(493,405)
Current tax provision (recovery) (Note 6)	115,472	(48,183)
Future income tax recovery	(372,250)	(4,500,000)
	(256,778)	(4,548,183)
Earnings (loss) before non-controlling interests (Note 11)	(2,967,481)	4,054,778
Income applicable to non-controlling interests	8,930	-
NET EARNINGS (LOSS)	(2,976,411)	4,054,778
RETAINED EARNINGS, BEGINNING OF YEAR	4,387,580	500,720
Change in accounting policy (Note 10d)	(200,000)	-
Change in accounting policy (Note 8)	-	(167,918)
RETAINED EARNINGS, END OF YEAR	1,211,169	4,387,580
EARNINGS (LOSS) PER SHARE (Note 14)		
Basic	(0.06)	0.13
Diluted	(0.06)	0.12

Consolidated Statements of Cash Flows

CONNACHER OIL AND GAS LIMITED

Years Ended December 31

	2004	2003
		(restated Notes 2 & 8)
	($)	($)
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net earnings (loss)	(2,976,411)	4,054,778
Items not affecting cash:		
Depletion, depreciation and accretion	6,876,110	3,707,429
Stock-based compensation (Note 10)	180,661	87,000
Future income tax recovery	(372,250)	(4,500,000)
Foreign exchange - non-cash portion	45,524	3,571
Gain on reorganization of Argentinean operations	(1,353,199)	-
Income applicable to non-controlling interests	8,930	-
Cash flow from operations	2,409,365	3,352,778
Changes in non-cash working capital (Note 14)	(9,428,723)	8,526,133
	(7,019,358)	11,878,911
FINANCING		
Issue of common shares, net of share issue costs	20,411,953	15,026,569
Issue of shares by subsidiary	1,385,037	-
Increase in (repayment of) bank loans	(12,100,000)	10,000,000
Lease inducement received	353,771	-
Repayment of note payable	-	(457,806)
	10,050,761	24,568,763
INVESTING		
Acquisition and development of oil and gas properties	(17,628,534)	(35,789,621)
Proceeds on disposal of oil and gas properties (Note 5)	17,604,310	-
Deposit on facilities	279,700	(279,700)
	255,476	(36,069,321)
NET INCREASE IN CASH	3,286,879	378,353
CASH, BEGINNING OF YEAR	627,302	248,949
CASH, END OF YEAR	3,914,181	627,302

SUPPLEMENTARY CASH FLOW INFORMATION (Note 14)

Years Ended December 31, 2004 and 2003

1. FINANCIAL STATEMENT PRESENTATION

The company is engaged in oil and gas exploration, development and production activities in Canada and in Argentina.

The consolidated financial statements include the accounts of the company and its subsidiary companies.

2. SIGNIFICANT ACCOUNTING POLICIES

Joint venture operations

A part of the company's activities are conducted with others, and these consolidated financial statements reflect only the company's proportionate interest in such activities.

Cash

Cash includes short-term deposits with initial maturities of three months or less.

Petroleum and natural gas operations

The company follows the full cost method of accounting whereby all costs relating to the exploration for and development of crude oil and natural gas reserves are capitalized on a country by country cost centre basis.

Capitalized costs of petroleum and natural gas properties and related equipment within a cost centre are depleted and depreciated using the unit-of-production method based on estimated proven crude oil and natural gas reserves as determined by independent consulting engineers. For the purpose of this calculation, production and reserves of natural gas are converted to equivalent units of crude oil based on relative energy content (6:1).

Costs of acquiring and evaluating unproved properties and major development projects are excluded from costs subject to depletion and depreciation until it is determined whether or not proved reserves are attributable to the properties or impairment occurs. Gains or losses on sales of properties are recognized only when crediting the proceeds to cost would result in a change of 20 percent or more in the depletion and depreciation rate.

Effective January 1, 2004, the company prospectively adopted Accounting Guideline 16 - "Oil and Gas Accounting – Full Cost" ("AcG-16"), which replaced Accounting Guideline 5 - "Full Cost Accounting in the Oil and Gas Industry". AcG-16 is similar to the previous standard, but modifies how the ceiling test is performed and is consistent with CICA section 3063 - "Impairment of Long-Lived Assets" - ("CICA 3063"), which the company also adopted in 2004. The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its estimated future cash flows. The impairment amount is the difference between the carrying amount and the estimated fair value of the asset. This approach incorporates risks and uncertainties in the expected future cash flows from proved and probable reserves, which are discounted using a risk free rate. The adoption of AcG-16 and CICA 3063 had no effect on the company's financial results.

Furniture, equipment and leaseholds

Furniture and equipment are recorded at cost and are being depreciated on a declining balance basis at rates of 20 percent to 30 percent per year. Leaseholds are amortized over the lease term.

Financial instruments

Financial instruments include accounts receivable, loan receivable, deposits, accounts payable and bank loans. All carrying values of financial instruments approximate fair value unless otherwise noted.

Credit risk

The majority of the accounts receivable is in respect of oil and gas operations. The company generally extends unsecured credit to customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which credit has been extended. The company has not historically experienced any material credit loss in the collection of accounts receivable.

Commodity and financial risk management

Effective January 1, 2004, the company prospectively adopted the CICA's Accounting Guideline 13 - "Hedging Relationships" ("AcG-13") and EIC 128 - "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" ("EIC-128"). AcG-13 addresses the types of items that qualify for hedge accounting, the formal

documentation required to enable the use of hedge accounting, and the requirement to evaluate hedges for effectiveness. EIC 128 requires that financial instruments that are not designated as hedges be recorded at fair value on the company's consolidated balance sheet, with subsequent changes in fair value recorded in earnings. The company has not entered into any derivative financial instruments. Therefore, the adoption of AcG-13 and EIC 128 had no effect on the company's financial results.

However, the company periodically enters into fixed price crude oil sales contracts for the physical delivery of its crude oil to reduce the exposure to commodity price fluctuations; and occasionally these contracts are denominated in Canadian dollars to mitigate foreign exchange risks. Additionally, the company's bank loans are subject to floating interest rates.

Foreign operations

The company is exposed to risks from foreign exchange rates as it operates internationally and holds foreign denominated cash and short-term investments.

Foreign currency translation

The company translates its foreign denominated monetary assets and liabilities at the exchange rate prevailing at year end. Non-monetary assets, liabilities and related depletion and depreciation are translated at historic rates. Revenues and expenses are translated at the average rate of exchange for the year. Any resulting foreign exchange gains or losses are included in operations.

Asset retirement obligations

Effective January 1, 2004, the Canadian Institute of Chartered Accountants' ("CICA") new standard on Asset Retirement Obligations was retroactively adopted by the company, with restatement of prior periods. This new section requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of oil and natural gas wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition. Under the new standard, the estimated fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the company's credit adjusted risk-free interest rate. The obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related oil and natural gas properties and a corresponding liability is recognized. The liability is accreted against income until it is settled or the property is sold and is included as a component of depletion and depreciation expense. The increase in oil and natural gas properties is depleted and depreciated on the same basis as the remainder of the oil and natural gas properties. Actual restoration expenditures are charged to the accumulated obligation as incurred.

Prior to 2004, the company estimated costs of dismantlement, removal and site restoration and recorded them over the remaining life of the proved reserves on the unit-of-production basis. The annual provision was included in depletion and depreciation expense and was accrued as a future site restoration liability on the balance sheet. Actual restoration expenditures were charged to the accumulated obligation as incurred.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. In 2004, the company prospectively adopted EIC 146 - "Flow-Through Shares". Accordingly, share capital is reduced and the future income tax asset is decreased by the tax benefits related to the expenditures at the time they are renounced. Previously, the company recorded the tax benefits renounced at the time the qualifying expenditures were incurred.

Revenue recognition

Petroleum and natural gas sales are recognized as revenue at the time the respective commodities are delivered to purchasers. Gains and losses on forward fixed price commodity contracts are included in petroleum and natural gas sales revenue when the gain or loss occurs.

Transportation costs

Consistent with the recommendations of new CICA Handbook Section 1100, transportation costs are disclosed as a separate expense in the consolidated statement of operations and retained earnings. Comparative amounts have been restated accordingly.

Stock-based compensation plan

Effective January 1, 2004, the CICA's new standard on stock-based compensation was retroactively adopted by the company, without restatement of prior periods. This new section requires that as at the date of grant the fair value of stock options granted to both employees and non-employees be determined and expensed over the vesting period. Stock compensation expense is included in general and administrative expenses and credited to contributed surplus. Upon exercise of the options, the exercise proceeds, together with amounts credited to contributed surplus, are credited to share capital. The company previously only expensed the fair value of stock options granted to non-employees.

Income taxes

The company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributed to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Future tax assets recognized are assessed by management at each balance sheet date for impairment.

Measurement uncertainty

The timely preparation of the consolidated financial statements in conformity with Canadian generally accepted accounting principles requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and accretion, asset retirement costs and obligations, amounts used for ceiling test and impairment calculations and amounts used in the determination of the future tax asset are based on estimates of natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty.

Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding for the period. The company follows the treasury stock method to calculate diluted per share amounts. The treasury stock method assumes that any proceeds from the exercise of in-the-money stock options and other dilutive instruments would be used to purchase common shares at the average market price during the period.

3. LOAN RECEIVABLE

The loan receivable was due from the operator of the Argentinean property concession in which the company held a 50 percent working interest. In 2004, the operator's interest was acquired and the loan receivable was recovered in full.

4. DEPOSITS – LONG TERM

A deposit on costs to construct a natural gas pipeline paid in 2003 were reimbursable over the next four years based upon volumes transported on the pipeline. During 2004 the company sold its interest in the pipeline and the costs were charged to property and equipment.

5. PROPERTY AND EQUIPMENT

	Cost $	Accumulated Depletion, Depreciation and Amortization $	Net Book Value $
2004			
Petroleum and natural gas properties and equipment	**46,616,971**	**10,654,358**	**35,962,613**
Furniture, equipment and leaseholds	**806,314**	**226,332**	**579,982**
	47,423,285	**10,880,690**	**36,542,595**
2003 (restated)			
Petroleum and natural gas properties and equipment	50,157,118	5,170,086	44,987,032
Furniture and equipment	305,504	114,888	190,616
	50,462,622	5,284,974	45,177,648

Included in Property and Equipment are estimated future asset retirement costs of $1,851,300 (2003 - $3,907,901).

In July 2004 the company sold certain petroleum and natural gas properties for gross proceeds of $17.6 million. As there was no significant change in the rate of depletion, no gain or loss was recognized. These financial statements reflect operating results from these properties until the date the sale closed. The asset retirement obligation was also reduced to reflect this disposition.

In 2004 the company acquired the non-owned 50 percent interest in an oil and gas concession in Argentina for US $1.5 million. The purchase price was negotiated at arms-length with the operator of the property. The company's 100 percent interest in the properties was subsequently sold to a related party, Petrolifera Petroleum Limited ("Petrolifera"). The company's carrying value was used to record the sale. As consideration for the properties sold, Connacher received a $4 million promissory note and eight million Petrolifera common shares. Immediately after the transaction, Petrolifera

paid $1.25 million in partial satisfaction of the promissory note from proceeds of an equity sale, which reduced Connacher's interest in Petrolifera to 61 percent (see Note 16).

In 2003 the company purchased producing oil properties in the Battrum area of southwest Saskatchewan in two separate transactions from independent oil companies for total cash consideration of $10 million.

In 2004, the company capitalized $70,700 (2003 - $204,300) of general and administrative expenses related to exploration and development activities and $113,000 (2003 – nil) of interest costs related to major development projects.

Capital costs of $4.4 million (2003 - nil) related to major development projects in a pre-production state have been excluded from depletable costs. No proved reserves have been assigned to those projects. Undeveloped land acquisition costs of $3.4 million (2003 - $3.4 million) were also excluded from the depletion calculation.

Depletion, depreciation and accretion expense includes a charge of $178,000 to accrete the company's estimated asset retirement obligations (Note 8).

The ceiling test as at December 31, 2004 excludes $3.4 million of unproved properties and $4.4 million of major development projects which have been separately evaluated by management for impairment. Based on the ceiling test and other assessments, no impairment has been recorded at December 31, 2004.

Connacher's oil and natural gas reserves were evaluated by independent reservoir engineers as at December 31, 2004 in a report dated March 2, 2005. The evaluation was conducted in accordance with Canadian Securities Regulators' National Instrument 51-101 ("NI 51-101"), using the following base price assumptions adjusted for the company's oil sales contract, its product quality and transportation differentials:

	WTI @ Cushing ($US/bbl)	Alberta Spot ($/mcf)
2005	45.00	6.87
2006	40.80	6.67
2007	36.41	6.45
2008	34.49	5.87
2009	32.47	5.51
	+ approximately 2% thereafter	+ approximately 2% thereafter

6. INCOME TAXES

The 2004 current income tax provision of $115,472 is comprised of Argentinean income taxes payable. The 2003 tax recovery of $48,183 was comprised of Argentinean taxes recoverable.

A future tax recovery of $372,000 was recorded in 2004. In 2003 the company recognized the tax benefit of its previously unrecognized tax assets, resulting in a recovery of $4.5 million.

The following table reconciles income taxes calculated at the Canadian statutory rate with recorded income taxes:

	Years Ended December 31	
	2004	**2003**
	$	$
Loss before income taxes and non-controlling interests	**(3,224,300)**	(493,405)
Canadian statutory rate	**39.1%**	42.15%
Expected income taxes recoverable	**(1,260,700)**	(208,000)
Non-deductible Canadian crown payments	**691,700**	551,500
Canadian resource allowance	**(366,600)**	(444,300)
Benefit (reduction) of tax deductions not previously recognized	**269,000**	(4,739,700)
Impact of reduction in Canadian tax rates	**294,300**	340,500
Foreign taxes (recovery)	**115,500**	(48,183)
Provision for taxes (recovery)	**(256,800)**	(4,548,183)

The company had the following deductible temporary differences:

	As at December 31	
	2004	**2003**
	$	$
Tax basis in excess of book value of property and equipment	**4,415,000**	5,143,100
Non-capital losses carried forward	**4,848,000**	6,283,900
	9,263,000	11,427,000

At December 31, 2004, the company had approximately $38 million of deductible tax pools in Canada.

Additionally, at December 31, 2004, the company had non-capital losses of $4,848,000 available to be carried forward for deduction against future taxable income. These losses do not expire before 2009.

7. BANK LOANS

As at December 31, 2004, the company had available a $6.6 million Revolving Reducing Demand Loan ("LOC") with no scheduled monthly reductions. The LOC bears interest at the bank's prime lending rate plus 3/4 percent on borrowed amounts. At December 31, 2004, the company had not drawn any amount on this facility.

Additionally, the company had a $2,000,000 Non-Revolving Acquisition/ Development Demand Loan Facility ("AD Facility"). At December 31, 2004, the company had not drawn any amount on this facility. Interest is charged at prime plus one percent on borrowed amounts of the AD Facility.

Amounts drawn on these loans are secured by a $50,000,000 fixed and floating charge debenture and a general assignment of book debts.

8. ASSET RETIREMENT OBLIGATIONS

The company has adopted the new CICA recommendations on the recognition of obligations to retire long-lived assets. The change was made effective January 1, 2004 and the revision was applied retroactively. The impact of this change was as follows:

Consolidated Balance Sheet – as at December 31, 2003

	As Reported	Change	As Restated
	$	$	$
Assets			
Property and equipment, net	41,269,748	3,907,900	45,177,648
Future income tax asset	4,402,320	200,000	4,602,320
Liabilities and shareholders' equity			
Asset retirement obligations	-	4,784,000	4,784,000
Provision for site restoration and abandonment	372,644	(372,644)	-
Retained earnings	4,691,036	(303,456)	4,387,580

As a result of adopting the new standard, the cumulative earnings impact of $303,456 at January 1, 2004 ($167,918 at January 1, 2003) has been charged to the opening balance of Retained Earnings. The impact of this new accounting policy for 2004 was to decrease the net loss by $178,000 (2003 - $135,500).

At December 31, 2004 the estimated total undiscounted amount required to settle the asset retirement obligations was $5.6 million. These obligations are expected to be settled over the useful lives of the underlying assets, which currently extend up to 16 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of six percent.

Changes to asset retirement obligations were as follows:

	Year ended December 31, 2004
	$
Asset retirement obligations, beginning of year	**4,784,000**
Liabilities incurred	**663,406**
Liabilities disposed	**(2,466,660)**
Accretion (included in depletion expense)	**178,000**
Revisions to estimates	**(46,496)**
Liabilities settled during the year	**(206,773)**
Asset retirement obligations, December 31, 2004	**2,905,477**

9. DEFERRED CREDITS

During 2004, the company received an office lease inducement which is being amortized against office rent expense over the six year term of the lease.

10. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized

The authorized share capital is comprised of the following:

- Unlimited number of common voting shares
- Unlimited number of first preferred shares
- Unlimited number of second preferred shares

Issued

Only common shares have been issued by the company.

	Number of Shares	Amount $
Share Capital:		
Balance, December 31, 2002	24,175,334	4,681,083
Issued for cash by private placement (a)	13,407,955	12,320,700
Assigned value of warrants issued (a)		205,500
Issued upon exercise of options (d)	534,000	133,000
Issued upon exercise of warrants (e)	7,785,636	3,236,114
Assigned value of warrants exercised (a)		(36,300)
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (f)		(575,680)
Share issue costs		(1,194,630)
Tax effect of share issue costs		478,000
Repayment of Share Purchase Loans and interest (b)		368,385
Balance, December 31, 2003	45,902,925	19,616,172
Issued for cash by private placement (c)	41,706,663	20,832,298
Assigned value of warrants issued (c)		441,700
Issued upon exercise of options (d)	575,000	178,236
Issued upon exercise of warrants (e)	1,442,155	766,788
Assigned value of warrants exercised (a)		(45,700)
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (f)		(1,970,000)
Share issue costs		(1,737,633)
Tax effect of share issue costs		673,700
Balance, Share Capital, December 31, 2004	89,626,743	38,755,561
Contributed Surplus:		
Balance, December, 31, 2002		97,533
Fair value of share options granted (d)		87,000
Share options exercised (d)		(6,200)
Balance, December 31, 2003		178,333
Change in accounting policy (d)		200,000
Fair value of share options granted (d)		180,661
Share options exercised (d)		(23,736)
Balance, Contributed Surplus, December 31, 2004		535,258
Total Share Capital and Contributed Surplus:		
December 31, 2003, restated (d)		19,794,505
December 31, 2004		39,290,819

(a) Private Placements - 2003

In March 2003 the company issued 4,542,155 units, consisting of one common share and one share purchase warrant ("warrant"), at a price of $0.45 per unit. Each warrant entitled the holder to purchase one additional common share from treasury at a price of $0.50 per share any time before February 28, 2005. For accounting purposes, a fair value of $143,500 was ascribed to the issued warrants. As partial compensation for distributing the private placement, selling agents were issued 227,107 warrants on the same terms. For accounting purposes, a fair value of $10,500 was assigned to these issued warrants. In 2004, 1,427,655 (2003 – 560,850) warrants were exercised. (Note 16)

In December 2003 the company issued from treasury 5,162,000 common shares at $1.05 per share and 3,703,800 flow-through common shares at $1.35 per share, renouncing resource expenditures of $5,000,130 effective December 31, 2003. As partial compensation for distributing the shares, selling agents were issued 310,303 warrants, each warrant entitling the holder to acquire one common share from treasury at a price of $1.18 on or before December 10, 2004. For accounting purposes, a fair value of $51,500 was assigned to these issued warrants, all of which expired in 2004 without being exercised.

(b) Share Purchase Loans

Pursuant to a Loan and Share Pledge Agreement dated July 5, 2001, the company provided a loan to the Chief Executive Officer in the amount of $200,000. This amount was secured by one million common shares and one million common share purchase warrants of the company, bore interest at bank prime and was due on the earlier of July 5, 2004 or the date of the sale of the securities.

Pursuant to a Loan and Share Pledge Agreement dated August 31, 2001, the company provided a loan to the Chief Operating Officer in the amount of $147,000. This amount was secured by 700,000 common shares and 700,000 common share purchase warrants of the company, bore interest at bank prime and was due on the earlier of August 31, 2004 or the date of the sale of the securities.

In 2003 the share purchase loans, including interest, were repaid.

(c) Private Placement – 2004

In November and December 2004 the company issued from treasury 30,000,000 common shares at $0.475 per share and 11,706,663 common shares on a flow-through basis at $0.60 per share, renouncing resource expenditures of $7,023,998 effective December 31, 2004. As partial compensation for distributing the shares, selling agents were issued 2,487,368 warrants, with each warrant entitling the holder to acquire one common share from treasury at a price of $0.59 anytime before June 7, 2006 and 2,400 warrants exercisable at $0.61 anytime before June 7, 2006. For accounting purposes a fair value of $441,700 was assigned to the issued warrants. None of these warrants were exercised in 2004.

(d) Stock Options

A summary of the company's outstanding stock option grants, as at December 31, 2004 and 2003 and changes during those years is presented below:

	2004		2003	
	Number of Shares	**Weighted Average Exercise Price**	**Number of Shares**	**Weighted Average Exercise Price**
		$		$
Outstanding, beginning of year	**2,830,000**	**0.45**	2,324,000	0.31
Granted	**2,138,000**	**0.57**	1,040,000	0.65
Expired	**(404,400)**	**0.53**	-	-
Exercised	**(575,000)**	**0.27**	(534,000)	(0.24)
Outstanding, end of year	**3,988,600**	**0.53**	2,830,000	0.45

All stock options have been granted for a period of five years. Stock options granted prior to 2004 are fully vested; 335,000 stock options granted in 2004 vest one-third upon grant, one-third one year after grant and one-third two years after grant and 1,803,000 options granted in 2004 vest one-third one year after grant, one-third two years after grant and one-third three years after grant. The table below summarizes unexercised stock options.

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (Years)
$0.20 - $0.30	530,000	1.6
$0.31 - $0.70	2,723,600	2.8
$0.71 - $1.00	495,000	3.7
$1.01 - $1.52	240,000	4.2
	3,988,600	

Effective January 1, 2004, the CICA's new standard on stock-based compensation was retroactively adopted by the company, without restatement of prior periods. This new section requires that as at the date of grant the fair value of stock options granted to both employees and non-employees be determined and expensed over the vesting period. Stock compensation expense is included in general and adminitstative expenses. The company previously only expensed the fair value of stock options granted to non-employees. This change resulted in a $200,000 decrease to the opening balance of Retained Earnings and a $200,000 increase in the opening balance of Contributed Surplus. The impact of adopting this new accounting policy was to increase the current year net loss by $146,090 (2003-nil)

In 2004 a compensatory non-cash expense of $180,661 (2003 - $87,000) was recorded in general and administrative expenses, reflecting the fair value of stock options granted and vested during the year.

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

	2004	2003
Risk free interest rate	**3.0%**	3.0%
Expected option life (years)	**3**	3
Expected volatility	**53%**	53%

The weighted average fair value at the date of grant of all options granted in 2004 was $0.22 per option (2003 - $0.22).

(e) *Share purchase warrants*

A summary of the company's outstanding share purchase warrants, as at December 31, 2004 and 2003 and changes during the years is presented below:

	2004	2003
Outstanding, beginning of year	**4,984,145**	7,670,216
Issued in the year	**2,499,768**	5,099,565
Exercised in the year	**(1,442,155)**	(7,785,636)
Expired in the year	**(741,233)**	-
Outstanding, end of year	**5,300,525**	4,984,145

The 5,300,525 warrants outstanding are exercisable to purchase common shares from treasury as follows:

(i) 2,800,757 common shares at $0.50 per share until their expiry on February 28, 2005 (Note 16);

(ii) 2,487,368 common shares at $0.59 per share until their expiry on June 7, 2006;

(iii) 2,400 common shares at $0.61 per share until their expiry on June 7, 2006; and

(iv) 10,000 common shares at $0.52 per share until their expiry on December 1, 2006;

(f) *Flow-through shares*

In 2004 the company incurred all of its $5 million resource expenditures commitment related to its 2003 flow-through common share financing and recognized the related tax effect of $1,970,000. Additionally, the company renounced a further $7,023,998 of resource expenditures to flow-through share investors effective December 31, 2004. The tax effect of those expenditures will be recorded in 2005; the company has until December 31, 2005 to incur those expenditures.

11. REORGANIZATION OF ARGENTINEAN OPERATIONS

In 2004 the company reorganized its Argentinean oil and gas properties by acquiring the non-owned 50 percent operated interest in an arms length transaction from its joint venturer for US $1.5 million. Late in 2004, Connacher incorporated a subsidiary, Petrolifera and sold its Argentinean assets to Petrolifera for eight million Petrolifera common shares and a $4 million promissory note (Note 5). Concurrent with acquiring the Argentinean assets from Connacher, Petrolifera closed a $1.5 million private placement equity financing consisting of common shares and common share purchase warrants. The financing had the effect of reducing Connacher's equity interest in Petrolifera from 100 percent to 61 percent, as Connacher did not participate in the financing. The 39 percent reduction in its holding resulted in a dilution gain to the company of $1,353,199 ($825,451, after tax). Immediately after the transaction, Petrolifera paid $1.25 million in partial satisfaction of the promissory note (Note 16).

12. SEGMENTED INFORMATION

The company has operations in Canada and Argentina; all operating activities are related to exploration, development and production of petroleum and natural gas as follows, including non-controlling interests:

	Canada	Argentina	Total
	$	$	$
2004			
Revenue, gross	**10,184,516**	**1,031,372**	**11,215,888**
Net earnings (loss)	**(3,049,181)**	**72,770**	**(2,976,411)**
Property and equipment	**33,723,669**	**2,818,926**	**36,542,595**
Capital expenditures	**17,013,221**	**615,313**	**17,628,534**
Total assets	**43,214,727**	**3,002,386**	**46,217,113**
2003			
Revenue, gross	9,273,279	709,012	9,982,291
Net earnings, restated (Notes 2 & 8)	3,883,511	171,267	4,054,778
Property and equipment, restated (Notes 2 & 8)	44,480,544	697,104	45,177,648
Capital expenditures	35,224,026	565,595	35,789,621
Total assets, restated (Notes 2 & 8)	52,694,969	1,082,008	53,776,977

13. RELATED PARTY TRANSACTIONS

The company paid the following amounts (including professional fees) to companies in which officers or directors of the company are related parties:

	2004	2003
	$	$
Consulting fees	**Nil**	167,200
Professional legal fees	**250,800**	200,000

Transactions with the foregoing related parties occurred within the normal course of business and have been measured at their exchange amount on normal business terms. The exchange amount is the amount of consideration established and agreed to by the related parties.

14. SUPPLEMENTARY INFORMATION

(a) Per share amounts

The following table summarizes the common shares used in per share calculations.

For the years ended December 31	2004	2003
Weighed average common shares outstanding	**50,907,942**	32,362,110
Dilutive effect of stock options and stock purchase warrants	**2,420,609**	2,971,014
Weighed average common shares outstanding - diluted	**53,328,551**	35,333,124

(b) Net change in non-cash working capital

For the years ended December 31	2004	2003
	$	$
Accounts receivable	**711,424**	(1,737,066)
Loan receivable	**135,848**	4,972
Prepaid expenses	**(12,053)**	(122,721)
Accounts payable	**(10,263,942)**	10,380,948
Total	**(9,428,723)**	8,526,133

(c) Supplementary cash flow information

For the years ended December 31	2004	2003
	$	$
Interest paid	**883,026**	755,566
Income taxes paid	**76,006**	14,092

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES (Note 16)

The company has entered into a crude oil sale agreement with an independent integrated oil company to sell 250 bbl/d medium gravity crude oil production at CDN $44.08 (before deduction for crude oil price differential) from April 1, 2004 to March 31, 2005. Management does not intend to renew this agreement at expiry.

The company's annual commitments under leases for office premises and operating costs, field compression equipment, software license agreements and other equipment are as follows:

2005 - $475,000; 2006 - $394,000; 2007 - $374,000; 2008 - $527,000; 2009 - $521,000; thereafter - $215,000.

Additionally, the company has various guarantees and indemnifications in place in the ordinary course of business, none of which are expected to have a significant impact on the company's financial statements or operations.

16. SUBSEQUENT EVENTS

(a) In January and February 2005, 2,785,757 of the common share purchase warrants exercisable at $0.50 until February 28, 2005, were exercised. This resulted in the issuance of the 2,785,757 common shares and the receipt of $1.4 million cash to the company.

(b) In March 2005, Petrolifera completed a $7 million private placement financing consisting of common shares and common share purchase warrants. As Connacher did not participate in the financing, its interest in Petrolifera was reduced to 40 percent. Petrolifera repaid $2 million of its indebtedness to Connacher from proceeds of the financing, reducing the amount owing to Connacher, pursuant to an outstanding promissory note to $750,000.

Also in March 2005, Petrolifera qualified to acquire two significant oil and gas exploration licenses in Peru. The licenses will be owned by Petrolifera when they are formally awarded. In exchange for its support and providing a guarantee for certain cost commitments of Petrolifera, Connacher received a 10 percent carried working interest through the drilling of the first well in each license, and an option to acquire up to 200,000 Petrolifera common shares at $0.50 per common share. Connacher's guarantee is limited to amounts specified over the terms of the licenses. Over the next 24 months, the guarantee is limited to US $200,000. Connacher has been indemnified from Petrolifera for this guarantee.

THREE-YEAR HISTORICAL SUMMARY

	2004	2003	2002
FINANCIAL HIGHLIGHTS			
($000 except per share amounts) - Unaudited			
Total revenue	**11,216**	9,982	4,326
Cash flow from operations (1)	**2,409**	3,353	1,047
Basic, per share (1)	**0.05**	0.10	0.05
Diluted, per share (1)	**0.05**	0.10	0.05
Net earnings (loss)	**(2,976)**	4,055	208
Basic, per share	**(0.06)**	0.13	0.03
Diluted, per share	**(0.06)**	0.12	0.03
Capital expenditures	**17,629**	35,790	9,014
Proceeds on disposal of oil and gas properties	**17,604**	-	-
Bank debt and note payable	**-**	12,100	2,558
Working capital deficiency (surplus)	**(3,549)**	8,994	846
Net debt (cash on hand)	**(3,914)**	21,094	3,404
Shareholders' equity	**40,502**	24,182	4,986
Total assets	**46,217**	53,777	12,692
OPERATING HIGHLIGHTS			
Production			
Natural gas (mcf/d)	**1,620**	1,190	1,365
Crude oil (bbl/d)	**785**	789	340
Equivalent (boe/d) (2)	**1,055**	987	568
Pricing			
Crude Oil ($/bbl)	**31.42**	30.03	25.30
Natural gas ($/mcf)	**3.62**	2.95	2.28
Selected Highlights ($/boe) (2)			
Weighted average sales price	**28.95**	27.56	20.64
Royalties	**5.54**	4.98	2.88
Operating and transportation costs	**9.75**	8.47	7.85
Netback (1), (2), (3)	**13.75**	14.25	10.15
Reserves (mboe) (2)			
Proved	**2,078**	3,085	1,513
Probable	**1,763**	2,489	249
Possible	**53,070**	1,484	-
Total	**56,912**	7,058	1,762
COMMON SHARE INFORMATION			
Shares outstanding at end of period (000)	**89,627**	45,903	24,175
Weighted average shares outstanding			
Basic (000)	**50,908**	32,362	19,890
Diluted (000)	**53,329**	35,333	20,377
Volume traded during the year (000)	**84,950**	39,445	84,946
Common share price ($)			
High	**1.75**	1.60	0.68
Low	**0.28**	0.30	0.20
Close, end of year	**0.55**	1.60	0.43

(1) Cash flow from operations, cash flow per share and netback are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other companies.

(2) Per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil (6:1). The conversion is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead.

(3) For detailed netbacks by product type and by country, see MD&A - "Operating Expenses and Operating Netbacks".

Corporate Information

officers

Richard A. Gusella
President and Chief Executive Officer

Peter D. Sametz
Executive Vice President and
Chief Operating Officer

Richard R. Kines
Vice President, Finance and
Chief Financial Officer

Timothy J. O'Rourke
Vice President, Oil Sands Operations

Jennifer K. Kennedy
Corporate Secretary
Partner, Macleod Dixon LLP

auditors
Deloitte & Touche LLP, Calgary

bankers
National Bank of Canada, Calgary

solicitors
Macleod Dixon, LLP, Calgary

reservoir engineers
DeGolyer and MacNaughton
Canada Limited, Calgary

registrar and transfer agent
Valiant Trust Company, Calgary
Equity Transfer Services Inc., Toronto

subsidiaries
COGL Resources Ltd. - (100%)
Great Divide Oil Corporation - (100%)
Petrolifera Petroleum Ltd. - (61%)

stock exchange listing
Toronto Stock Exchange
Trading symbol - CLL

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board of directors

Richard A. Gusella
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Charles W. Berard (2, 3)
Chairman, Governance Committee
Partner, Macleod Dixon LLP, Calgary

Colin M. Evans (1, 2, 3, 4)
President, Evans & Co. Inc., Calgary

Gary W. Freeman (1, 3)
Chairman, Human Resources Committee
Co-founder and Director,
Spirit Energy, Calgary

Stewart D. McGregor (1, 2, 5)
Chairman, Audit Committee
President, Camun Consulting Ltd.

(1) **Audit Committee**
(2) **Governance Committee**
(3) **Human Resources Committee**
(4) **Chairman, Audit Committee, effective March 23, 2005**
(5) **Lead Director, effective March 23, 2005**

Abbreviations

ARTC
Alberta Royalty Tax Credit

bbls
barrels

bbl/d
barrels per day

bcf
billion cubic feet

boe
barrels of oil equivalent

boe/d
barrels of oil equivalent per day

DCF
discounted cash flow

GJ
gigajoule

mbbls
thousand barrels

mboe
thousand barrels of oil equivalent

mcf
thousand cubic feet

mcf/d
thousand cubic feet per day

mmbbls
million barrels

mmboe
million barrels of oil equivalent

mmcf
million cubic feet

mmcf/d
million cubic feet per day

NGLs
natural gas liquids

PV
present value

WI
working interest

WTI
West Texas Intermediate

designed & produced by iradesso communications

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